Decision ___________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (E 338-E) for Authority to Institute a Rate Stabilization Plan with a Rate Increase and End of Rate Freeze Tariffs.	Application 00-11-038 (Filed November 16, 2000)
Emergency Application of Pacific Gas and Electric Company to Adopt a Rate Stabilization Plan. (U 39 E)	Application 00-11-056 (Filed November 22, 2000)
Petition of THE UTILITY REFORM NETWORK for Modification of Resolution E-3527.	Application 00-10-028 (Filed October 17, 2000)

(See Appendix D for a list of appearances.)

OPINION ADOPTING REVENUE REQUIREMENTS FOR UTILITY RETAINED GENERATION

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OPINION ADOPTING REVENUE REQUIREMENTS FOR UTILITY RETAINED GENERATION

This decision establishes cost-of-service revenue requirements for the utility retained generation (URG) of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison) and San Diego Gas & Electric Company (SDG&E). URG reflects the utility-incurred costs associated with utility-owned generation assets and purchased power.[1] The URG revenue requirement is calculated based on operating expenses, purchased power costs, depreciation, taxes, and a return on rate base (derived from the net book value of retained plant). We adopt a January 2002 to December 2002 URG revenue requirement of $2.875 billion for PG&E, $3.794 billion for Edison, and $466 million for SDG&E. In general, we establish the URG revenue requirements by authorizing recovery of actual and reasonably incurred costs. Therefore, the initial revenue requirement we adopt in this decision will be trued-up to reflect actual recorded costs.[2] We adopt balancing accounts for PG&E, Edison, and SDG&E to ensure that these costs will be recovered.

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[1] In Decision (D.) 01-01-061, the Commission defined URG broadly to include generation under utility control.

[2] On October 2, 2001, the Commission and Edison entered into a settlement agreement, which may impact recovery of Edison's URG revenue requirement. Due to timing, the settlement agreement was not fully considered in this proceeding.

I. Procedural Background

Seven days of evidentiary hearings were held to determine the URG revenue requirements of PG&E, Edison and SDG&E.[3] In an Assigned Commissioner's Ruling (ACR) dated August 10, 2001, President Lynch accelerated the briefing schedule by directing parties to file and serve briefs on August 17, 2001, that addressed the issue of whether a market valuation approach for determining URG revenue requirements should be used. In D.01-10-067, mailed on October 30, 2001, the Commission rejected PG&E's market valuation approach for determining a prospective revenue requirement for URG. Concurrent opening briefs and reply briefs on remaining URG issues were filed on August 22 and August 29.

II. Organization

Typically, we would address issues individually and apply the same result, to the extent possible, to all affected utilities. We follow this approach for some key policy issues such as the scope of this decision. However, since the utilities' proposals emphasize different issues and contain varying levels of detail,[4] rather than use a one-size fits all approach, we will address specific cost issues and adopt URG revenue requirements that address the specific circumstances of each utility.

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[3] Evidentiary hearings were on Monday, July 23 through Friday, July 27, 2001, and also on Monday, July 23 and Tuesday, July 24, 2001.

[4] PG&E's original testimony was over 100 pages long whereas SDG&E only presented six pages of testimony.

III. Scope

Prior to addressing specific issues, we define the scope of this decision. In this decision, we determine a revenue requirement to ensure recovery of URG costs on a going forward basis. Consistent with D.01-01-061 and D.01-10-067, we limit the scope of this decision to establishing cost-based revenue requirements for URG that reflect actual and reasonable URG costs on a going forward basis.[5]

In this phase of the rate stabilization proceeding (RSP), both PG&E and Edison have sought recovery in the URG revenue requirement of past expenses incurred during the rate freeze. The recovery of "past expenses" is a distinct issue from establishing a prospective URG revenue requirement. We affirm Administrative Law Judge (ALJ) DeUlloa's July 18, 2001 ruling in which he ruled among other things that:

> "The scope of the evidentiary hearing set to begin on July 23, 2001, is the determination of utility retained generation asset (URG) revenue requirements. Issues concerning stranded cost recovery or the end of the rate freeze will not be addressed."

Although we adopt a URG revenue requirement on a going forward basis, we do not preclude in this decision, the possibility of later modifications to the utilities' URG revenue requirements to account for what were previously considered as stranded or uneconomic costs. In D.02-01-001, we explicitly provided for our further consideration of the utilities' recovery of such costs.

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[5] The Cogeneration Association of California (CAC) submitted a brief which requested that past QF costs be recorded in balancing accounts for recovery in the utilities' URG revenue requirement. The relief sought by CAC extends beyond the scope of this proceeding.

IV. Standard of Review and 2002 Interim URG Revenue Requirements

In establishing URG revenue requirements, we must address the level of scrutiny to apply in reviewing the utilities' proposals. Although we address each utility proposal separately, we apply the same level of scrutiny to all three utilities.

Typically, a Commission proceeding addressing utility costs consumes substantial time analyzing the reasonableness of such costs. However, the current energy situation has required expeditious preparation of forecasts by the utilities and a similar rapid review by staff, intervenors and the Commission. Normally, parties have a greater amount of time to perform discovery and analyze other parties' presentations. Thus as a consequence of time constraints, the costs presented have undergone a less thorough review than normal. As most parties have stated, the expedited nature has significantly affected the reliability of the data presented at hearing.

In response to the limited review, some parties have proposed using "best estimates" or forecasts to establish revenue requirements and then true-up forecasted costs with recorded actual costs. The utilities have proposed using recorded costs for some aspects of URG, and forecasts for others. The Utility Reform Network (TURN) proposes cost recovery on a recorded cost basis across the board. As we noted in D.97-12-096, we generally do not favor recorded cost ratemaking. However, in this instance, we find TURN's cost recovery proposal appealing because it reflects a straightforward approach that ensures the utilities will recover actual incurred costs.

Under TURN's cost recovery proposal, the Commission avoids the problems associated with outdated forecasts. We agree with Marcus, TURN's witness, that in the absence of the type of evaluation that typically occurs in a general rate case (GRC) or similar proceeding, a forecast is not a useful or reasonable basis for establishing a revenue requirement to be used later for setting rates.

TURN recommends using figures from the utilities' cost-based proposals and excluding fuel prices to set an initial revenue requirement. The initial revenue requirement would be subsequently balanced against actual costs. TURN argues that such a true-up is critical given that the short time frame for this proceeding renders it impossible for TURN to fully test utility forecasts. Although TURN prefers test-year ratemaking and consideration of incentive ratemaking, it does not believe that the Commission can fairly implement either at this time. TURN also proposes that the Commission review recorded costs for reasonableness.

In this instance, it is reasonable to limit recovery to actual recorded costs. We will adopt TURN's cost recovery approach. With respect to reasonableness review of such costs, Aglet Consumer Alliance (Aglet) notes that for some aspects of utility operations, the work associated with tracking costs outweighs the savings benefits to consumers. As discussed in more detail below, we agree and will adjust the utilities' revenue requirement to reflect a limited suspension of reasonableness review during this interim revenue requirement period.

In addition, Aglet contends the Commission should adopt only interim ratemaking in this phase of the RSP. Aglet asserts that interim ratemaking is appropriate until the applicants and interested parties can address the full range of cost issues in upcoming GRCs.

The Office of Ratepayer Advocates (ORA) also recommends that the Commission adopt the ratemaking mechanisms for utility retained generation in this proceeding as interim. ORA states that the Commission should require the three utilities to include generation-related costs in their next GRC in order to provide the Commission with a better opportunity to review and analyze these costs. ORA contends that such an approach will provide the Commission with a historical perspective on how much volatility and risk is associated with the ratemaking mechanisms adopted in this proceeding. Thus, ORA argues that the Commission can revise or eliminate these ratemaking mechanisms as necessary.

In the utilities' respective GRC proceedings, we shall establish a new URG revenue requirement based on a more detailed showing and review. The URG revenue requirements we adopt are interim in the sense that such revenue requirements may be used only as a guide in future GRC proceedings and will also be trued-up. The URG revenue requirements we adopt here are for the time period January 2002 to December 2002.

We discuss the balancing accounts to be established in Section IX.

V. PG&E

In its updated testimony, PG&E presented three URG revenue requirement scenarios as follows:

Scenario	Revenue Requirement ($ billions) [6]
1	$6.418
2	$3.783
3	$9.787

[6] See Exhibit URG-34. (Appendix A contains three detailed tables showing PG&E's three URG revenue requirement scenarios.)

Scenario one represents PG&E's proposal, which determines a URG revenue requirement using a market valuation for PG&E's retained generation. Scenarios two and three are not PG&E's proposals but instead represent PG&E's response to a Chief ALJ Ruling dated June 15, 2000, which required PG&E's testimony to include a scenario that values its hydroelectric assets using the actual net book value. PG&E does not endorse scenarios two and three.

Under scenario one, PG&E values its hydroelectric facilities, including its Helms Pumped Storage facility, at $4.1 billion. PG&E values its Humboldt Bay Power Plant at zero. PG&E asserts that the revenue requirement for Diablo Canyon should be determined using a 50/50 sharing of audited profits. The annual URG revenue requirement in scenario one is $6.418 billion, including purchased power costs.

Scenario two is based on PG&E's interpretation of the TURN accounting proposal adopted in D.01-03-082. PG&E's URG revenue requirement in scenario two is based on PG&E's data (April 2001), after it implemented the TURN accounting proposal.[7] PG&E believes that D.01-03-082 requires the Commission to establish PG&E's URG revenue requirements based on the combined balances in PG&E's generation-related accounts, including unamortized book value of plant. Specifically, PG&E argues that all unrecovered costs in the combined balances of the Transition Revenue Account (TRA), Transition Cost Balancing Account (TCBA), Generation Asset Balancing Account (GABA), generation memorandum accounts and generation plant accounts now constitutes the

[7] PG&E has not yet filed its reports implementing this accounting change, and the Commission has not yet ruled on Edison's analogous filing.

amount PG&E should recover through its URG revenue requirement. The annual URG revenue requirement for PG&E in scenario two is $3.783 billion, including purchased power costs.

In scenario three, PG&E also asserts that it has applied the TURN accounting proposal. However, in scenario three PG&E contends that it is entitled to recover by the end of 2001, through an accelerated amortization schedule, amounts in regulatory accounts, including GABA. PG&E states that its accelerated recovery approach is consistent with Edison's Advice Letter (AL) Filing 1535-E, dated April 11, 2001.[8] PG&E also contends that it is entitled to collect unrecovered power costs prospectively in its URG revenue requirement. In addition, PG&E argues that the Commission should value PG&E's generation rate base using the values PG&E filed in August 2000 pursuant to D.00-02-048 and D.00-06-004. In August 2000, PG&E recorded its estimated value of its remaining non-nuclear generation assets in the TCBA and GABA. The annual URG revenue requirement for PG&E in scenario three is $9.787 billion, including purchased power costs.[9]

PG&E calculates its revenue requirement by adding together its total annual operating expenses (including taxes and depreciation) plus a return on its investment or rate base. We address the reasonableness of PG&E's proposals below.

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[8] AL 1535-E has not been approved by the Commission and PG&E has not made an analogous filing. However, PG&E states that it estimated the unrecovered rate base for its retained generation assets using Edison's methodology.

[9] Under scenario three, PG&E states that Commission must recalculate PG&E's URG revenue requirement once the rate freeze ends.

A. Total Operating Expenses

1. PG&E

PG&E's "total operating expenses" includes: (1) operating expenses, (2) taxes, and (3) depreciation. (See Appendix A.) PG&E proposes total operating expenses for 2001 for fossil and hydro generation as follows:

- $680 million (includes $155 million in taxes and $156 million in depreciation) in scenario one;
- $1.213 billion (includes $469 million in taxes and $421 million in depreciation) in scenario two; and
- $3.245 billion (includes $79 million in taxes and $2.77 billion in depreciation) in scenario three.

PG&E's proposal for total operating expenses for 2001 for Diablo Canyon generation is addressed in Section V.C.

PG&E proposes total operating expenses for 2001 for Electric Energy Transaction Administration Expenses (EETA)[10] as follows:

- $25 million (includes $4 million in taxes and $4 million in depreciation) in scenario one;
- $25 million (includes $4 million in taxes and $4 million in depreciation) in scenario two; and

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[10] EETA include the costs of activities associated with purchasing electricity from the market, purchasing electricity under contracts with QFs and under other power purchase agreements, and managing PG&E's owned generation. EETA does not include commodity costs. PG&E proposes a 2001 revenue requirement of $30 million for EETA in scenarios one and two, and $31 million in scenario three.

- $26 million (includes $4 million in taxes and $5 million in depreciation) in scenario three.

PG&E's estimate for operating and maintenance (O&M) expenses for 2001 includes labor, materials, supplies, contracts, and other related expenses for operating and maintaining PG&E's generation facilities and for purchasing power on behalf of PG&E's bundled service customers.

PG&E states that it derived its 2001 forecast for O&M expenses for fossil (including fuel), hydro (including water costs) and Diablo Canyon (including nuclear fuel) by using 2000 recorded costs for these activities, adjusting for anticipated changes in 2001, and adding one year of escalation.

In addition to O&M expenses, PG&E incurs other operating expenses for Administrative and General (A&G), uncollectibles and franchise fees. PG&E also incurs expenses for depreciation and taxes.

2. TURN

TURN recommends that the Commission use recorded costs for generation O&M (including fuel, pumping energy, O&M, A&G, payroll taxes) through the end of 2002, subject to existing Commission ratemaking policies, such as allowing rate recovery for only one-half of A&G performance bonuses allocated to generation.

3. ORA

ORA contends that PG&E's estimates for fossil fuels operating costs are unreasonably large because of record-breaking fuel costs experienced in the first few months of 2001. ORA recalculated the O&M expenses PG&E presented in its second scenario to conform to the assumption that fuel costs will not change significantly in 2002. ORA did not change A&G expenses but recalculated depreciation, return on rate base, and the total revenue requirement.

Whereas PG&E scenarios reflect costs for 2000, ORA's forecast has been adjusted to a mid-2001 to mid-2002 time frame. ORA recommends that the Commission use the lessor of recorded O&M and A&G expenses versus PG&E's forecast.

4. Aglet

Aglet recommends setting a URG revenue requirement using actual operating costs, subject to a reduced return on equity (ROE) to reflect the loss of reasonableness review risk. Aglet estimates that the suspension of the reasonableness review risk is equivalent to approximately 130 points of ROE for PG&E, based on a 1% discounting of operating costs. Aglet also states that cost of capital adjustments are preferable to retrospective review because operating expenses are the result of many daily decisions in various areas of operation.

5. Discussion

The record demonstrates that PG&E's forecast of operating expenses is overstated due to PG&E's assumption of continually rising fuel prices and reliance on early 2000 gas prices. ORA uses a more recent and reasonable time period (July 2001 to June 2002) for its forecast. Thus, for purposes of establishing an interim URG revenue requirement, ORA's forecast of $549 million for total operating expenses for fossil and hydro generation should be adopted. Similarly, PG&E's forecast of $25 million for total operating expenses for EETA should be adopted since it is uncontested. In Section V.C. below, we discuss PG&E's operating expense revenue requirement for Diablo Canyon.

Adoption of TURN's cost recovery proposal ensures that PG&E will be made whole for its actual and reasonably incurred operating expenses. This is a straightforward approach that ensures that PG&E will recover its actual and reasonable recorded costs. We reject ORA's recommendation to use the lessor of recorded costs versus PG&E's forecast since this approach seems biased against PG&E.

For some aspects of utility operations, the work associated with reviewing costs for reasonableness outweighs the savings benefits to consumers. Performing a retrospective review of many daily decisions associated with O&M costs may yield an unmanageable task not worth the effort under the current circumstances. The recent shift from market pricing to cost-based pricing also adds additional burden to the task of reasonableness reviews. Therefore, we suspend reasonableness reviews for PG&E's O&M costs in establishing an interim revenue requirement.

By taking this approach, we reduce the financial risk to PG&E by guaranteeing the recovery of actual recorded costs without concern for reasonableness review. Such a reduction in risk should be associated with an equivalent reduction on ROE. We do not reduce PG&E's ROE, but do discount the O&M expenses to reflect this reduced risk. Using Aglet's approach, we calculate a reduced risk of 130 basis points which yields a 2.12% discount in authorized O&M revenue requirements. We therefore reduce ORA's recommended O&M revenue requirement for fossil and hydro generation of $289 million by approximately $6 million.

The reduction in oversight of O&M expenses should not be viewed as an abandonment or reduction in the need for reasonableness review and the critical role this regulatory tool plays in motivating utilities to make sound economic decisions that benefit both shareholders and ratepayers. Reasonableness reviews constitute the minimum concession utilities make in exchange for the benefits received from cost-of-service regulation such as the assurance of recovery of all reasonably incurred expenses and a guaranteed return on equity. In this instance, the suspension of reasonableness review reflects a response to the strains placed on parties from returning to the practice of establishing a cost-based revenue requirement and not a departure from the practice of using reasonableness reviews in cost-based regulation.

Allowing an exemption of reasonableness review does not equate to an exemption from record-keeping. Prior expenses form a basis for future forecasts and may be relevant data in future Commission proceedings. Consequently, PG&E should create and retain records for O&M costs in a manner that is consistent with past record-keeping practices for establishing a cost-based revenue requirement and make such records available to parties in future Commission proceedings.

B. Rate Base

Parties devoted substantial time presenting their positions on how PG&E's rate base should be determined. The matter is important because PG&E is entitled to depreciation expense and a return on the capital invested in rate base. Some of the issues raised were addressed in an interim order in D.01-10-067.

1. PG&E

PG&E uses "starting point balances" in calculating its rate base.[11]

In scenario one, PG&E proposes a starting point balance of $4.1 billion for fossil and hydro generation assets in service. PG&E determined

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[11] PG&E determined its rate base by adding together plant-in-service and working capital, and then it subtracted deferred taxes and depreciation reserve. PG&E describes plant-in-service as consisting of two components, (1) a starting point balance, and (2) capital additions.

this starting point balance by applying a "market valuation" to the PG&E-owned non-nuclear generation assets. In scenario one, PG&E does not provide a starting point balance for Diablo Canyon because it is fully recovered under PG&E's sharing proposal for Diablo Canyon. (Below in Section V.C.3, we address PG&E's sharing proposal for Diablo.)

In scenario two, PG&E describes its starting point balance as a combination of net book value of generation assets and amounts in regulatory balancing accounts. PG&E states:

> "the starting point balance for fossil, hydro and Diablo generation is equal to the (1) under-collected Transition Cost Balancing Account (TCBA) balance as of April 30, 2001 ($6.086 billion) plus (2) the Generation Asset Balancing Account (GABA) balance as of April 30, 2001 ($2.211 billion); (3) the unamortized net book value of plant as of April 30, 2001 ($969 million for fossil and hydro and $563 million for Diablo); and (4) the unamortized generation-related regulatory asset balance ($164 million)."

From the above description of starting point balance, PG&E determines that rate base in scenario two for fossil and hydro is $9.056 billion; and rate base for Diablo is $408 million.

In scenario three, PG&E describes its starting point balance as a combination of net book value of generation assets, unamortized regulatory assets and balance in the GABA account.

> "the starting point for fossil, hydro and Diablo generation is equal to: (1) the net book value as of December 31, 2000 ($1,105 million for fossil and hydro and $1,100 million for Diablo); plus (2) the unamortized generation-related regulatory asset balance ($307 million), both of which are adjusted for the unrecovered TCBA amortization in 2000; and (3) the GABA balance as of December 31, 2000 ($2,171 million).

From the above description of starting point balance, PG&E determines that its rate base in scenario three for fossil and hydro is $1.569 billion, and rate base for Diablo is $525 million.

In all three scenarios, PG&E states that the starting point balance for EETA is $62 million which is based on net book value as of December 31, 2000.

Using $62 million as a starting point balance, PG&E determines that rate base for EETA is $53 million.

2. ORA

ORA proposes using net book value as of December 31, 2000 to calculate rate base. ORA proposes a rate base amounts of $985 million for fossil and hydro; $948 million for Diablo Canyon; and $53 million for EETA.[12]

ORA believes that PG&E's proposals lack support and or omit critical details about ratemaking. ORA argues that PG&E's proposed market value is based on flawed price assumptions about a competitive market that does not exist.

ORA criticizes PG&E's second scenario for using numbers that would result if the rate freeze had never happened. ORA also contends that PG&E does not define, list, justify or describe what constitutes "PG&E's generation-related accounts." For instance, ORA states that the TCBA includes not merely capital costs, but a host of operating costs. ORA argues that PG&E does not explain how it converts unrecovered costs into unrecovered capital costs.

Under scenario three, ORA believes that PG&E's proposal focuses on recovery of undercollections rather than the establishment of cost-based URG revenue requirement. Under PG&E's approach, ORA states that PG&E sets revenue requirements based on a six-month recoverability period rather than using the useful lives of assets.

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12 See Exhibit URG-25, Appendix 2.2.

3. TURN

TURN recommends setting rate base equal to the end-of-year 2000 book value including past capital additions and subtracting decommissioning costs previously recovered. TURN would use this rate base as the basis for depreciation, property taxes, return, and income taxes. TURN recommends making return, taxes, and depreciation related to capital additions not previously approved subject to refund in the event of disapproval in a reasonableness review.

TURN opposes PG&E's market value approach. TURN asserts that the general theoretical flaw of PG&E's approach is that it defines generation cost-of-service as including procurement costs incurred in the past but not recovered in rates collected at the time. TURN contends that PG&E is inappropriately attempting to convert uncollected procurement costs into rate base. TURN also criticizes PG&E's market valuation approach as flawed because it presumes statutorily prohibited outcomes, i.e., sale of plant's output into a competitive market contrary to Section 377.

4. Discussion

In D.01-10-067, we rejected the market valuation approach which PG&E uses in its first scenario as well as PG&E's proposal (contained in scenarios two and three) to recover balances in generation related balancing accounts via its URG revenue requirement. We reasoned that these approaches were not cost-based, but instead sought to recover expenses previously considered to be stranded costs.

In scenario two, PG&E argues that since D.01-03-082 indicated that the first costs to be recovered during the transition period were operating costs, including PX costs and other Federal Energy Regulatory Commission

(FERC)-approved costs, that therefore, the remaining costs must be recovered through generation rates. PG&E's analysis in scenario two also raises issues concerning the recovery of stranded costs. Such issues are beyond the scope of this decision. We neither prejudge nor resolve PG&E proposals dealing with recovery of stranded costs in this decision and leave the matter open for future resolution, consistent with the direction provided in D.02-01-001.

As an interim approach, we find that net book value as of December 31, 2000, is the appropriate value to use for rate base for non-nuclear generation (below in Section V.C, we address Diablo Canyon). Net book value is the original cost of a particular asset adjusted for accumulated depreciation and excludes from rate base any unrecovered costs unrelated to prospective URG costs. Net book value provides PG&E an opportunity to recover its original investment in plant. We are inclined to use PG&E's figure in determining a rate base based on net book value. However, although PG&E refers to net book value of its generation assets in its description of "starting point balances," PG&E does not provide sufficient information to determine a rate base using net book value. PG&E provides some explanation for how it determined plant-in-service, but does not provide sufficient detail on working capital, deferred taxes and depreciation reserve. PG&E's testimony lacks a detailed analysis to confirm PG&E's calculation of rate base from its starting point balances or an accounting for how it adjusts starting point balances for capital additions, deferred taxes and depreciation.

As an interim measure until PG&E's next GRC, ORA's net book values ($985 million for fossil and hydro generation) as of December 31, 2000, should be adopted for purposes of establishing PG&E's rate base. PG&E's net book value of $53 million is uncontested and should be adopted for purposes of establishing an interim rate base for EETA.

C. Diablo Canyon

1. PG&E

In scenario one, PG&E requests a revenue requirement of $1.275 billion for Diablo Canyon. In scenario one, PG&E assumes that its investment in Diablo Canyon is fully recovered, and consequently, PG&E does not request an amount for rate base for Diablo Canyon. In scenario one, PG&E requests the adoption of a 50/50 sharing mechanism for Diablo Canyon which PG&E first proposed in Application (A.) 00-06-046. PG&E's proposal presumes an end to the rate freeze. PG&E incorporated relevant portions of A.00-06-046 into its testimony in this proceeding.[13]

In scenario two, PG&E forecasts a 2001 revenue requirement of $393 million for Diablo Canyon that PG&E states is based on traditional cost-of-service calculations. PG&E asserts that it had insufficient time to examine alternatives to traditional cost-of-service regulation and to determine a 2002 Diablo Canyon cost-of-service revenue requirement. If scenario two is adopted, PG&E's suggests that the Commission should re-examine the revenue requirement for 2002 under a schedule that allows more time to evaluate alternatives.

In scenario 3, PG&E assumes the rate freeze is still in effect and therefore calculates a Diablo Canyon revenue requirement using its Incremental

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[13] See Chapter 3 of Exhibit URG- 11.

Cost Incentive Pricing (ICIP) mechanism. In scenario three, PG&E requests a revenue requirement of $2.173 billion for Diablo Canyon.

PG&E proposes total operating expenses for 2001 for Diablo Canyon generation as follows:

- zero in scenario one (the revenue requirement is based on PG&E's 50/50 sharing proposal);
- $356 million (includes a $10 million credit for taxes and $56 million in depreciation) in scenario two; and
- $2.125 billion (includes $400 million in taxes and $1.101 billion in depreciation) in scenario three.

2. Aglet

Aglet opposes any continuation of ICIP ratemaking for Diablo Canyon. Under cost-based ratemaking, Aglet asserts that the profit sharing element of ICIP is not a just and reasonable utility cost.

3. TURN

TURN believes that the PG&E's 50/50 sharing mechanism proposal would dramatically raise rates and pre-tax profits for shareholders by charging ratepayers for Diablo Canyon power in excess of the costs to produce. Instead, on an interim basis, TURN proposes adoption of a Nuclear Incentive Program (NUIP), similar to the treatment applied to the Palo Verde nuclear facility, for all fuel cycles beginning after the end of the ICIP period. Under this plan, PG&E would receive one-half of the difference between replacement power costs and nuclear fuel costs for output in excess of 80%, with replacement power costs capped at 5¢ per kilowatt-hour (kWh). For determining rate base, TURN believes that the Commission should use book value as of December 31, 2000. As an interim measure, TURN recommends that depreciation for Diablo Canyon should be calculated over a remaining life of 15 years. TURN asserts that no basis exists for accelerating nuclear depreciation.

4. ORA

ORA proposes the termination of ICIP pricing for Diablo Canyon at the end of 2001. ORA states that PG&E should receive a revenue requirement for Diablo Canyon that is based on cost-of-service and that PG&E should recover any remaining Diablo Canyon sunk costs over the remaining plant life. Also, ORA recommends a rate of return of 9.12% for 2002.

5. Discussion

Aglet, TURN and ORA all oppose PG&E's proposed 50/50 sharing mechanism for Diablo Canyon. These parties support termination of ICIP pricing and recommend that Diablo Canyon should return to cost-of-service ratemaking.

PG&E's 50/50 sharing proposal mechanism lacks merit. PG&E's proposal is premised on the assumption that the rate freeze has ended, a finding that the Commission has not made. In fact, the proceeding dealing with PG&E's sharing proposal, A.00-06-046 has been suspended because a determination has not been made that the rate freeze has ended. In addition, under PG&E's 50/50 sharing proposal, ratepayers would likely pay in excess of the costs to produce power. Thus, the revenue requirement for Diablo Canyon would not be cost-based.

In D.01-01-061, we placed PG&E on notice that URG revenue requirements should be cost-based. ICIP should be modified since it does not produce a cost-based URG revenue requirement. However, the record is insufficient to determine a cost-based revenue requirement for Diablo Canyon.

Therefore, subject to true-up against actual recorded costs, the Diablo Canyon revenue requirement contained in PG&E's second scenario should be used as an interim revenue requirement since it purportedly relies on cost-based calculations. Application of TURN's cost recovery proposal should ensure that PG&E suffers no economic harm or taking since PG&E will recover all of its actual and reasonable costs incurred for nuclear generation. A Diablo Canyon revenue requirement of $393 million and a rate base of $408 million, consistent with PG&E's second scenario, should be adopted. This revenue requirement is derived from the $356 million in operating expenses and $37 million in return. PG&E calculates the return by applying 9.12% to a rate of base of $408 million.

The depreciation life PG&E uses in scenario two is a 10-year life which we will adopt as an interim revenue requirement. Spread over 10 years, the depreciation for Diablo is $56 million per year using straight-line depreciation. In PG&E's next GRC, the issue of depreciation life for Diablo Canyon should be addressed with a particular focus on determining the useful life of the plant. All of PG&E's nuclear generation costs should be subject to reasonableness review since we have modified PG&E's method of recovering such costs.

D. 2001 Plant Additions

1. PG&E

PG&E states that it adds capital expenditures to plant-in-service when the specific capital project becomes operational. PG&E estimated its total anticipated capital expenditures for 2001 based on costs for labor, material, material burden, external contracts, escalation, capitalized A&G, allowance for funds used during construction (AFUDC), and other related costs it incurs while purchasing or constructing an asset. PG&E states that all of these cost elements added together result in the total financial capital investment for a project.

In all scenarios, PG&E forecasts 2001 capital expenditures of $19.4 million for fossil capital additions to replace obsolete equipment, replace fossil transformers, perform seismic retrofits and environmental upgrades and make emergency fossil equipment replacements.

PG&E also forecasts 2001 capital expenditures of $30 million for hydro capital additions to replace obsolete equipment, implement FERC's license conditions, implement safety modifications to water conveyance and reservoir facilities and replace hydro equipment following storms and other emergencies. PG&E states that it established the 2001 capital budgets in 2000, when it presumed that these assets would be divested. PG&E states that it therefore has limited its forecast to projects that provide immediate ratepayer benefits. PG&E expects the 2002 and 2003 capital budgets to increase significantly as it implements a long-term, least-cost maintenance program.

In all scenarios, PG&E forecasts 2001 expenditures of $13.2 million for Diablo Canyon capital additions to replace of aging or obsolescent plant equipment, infrastructure improvements, and enhancement of plant operational safety.

2. Aglet

Aglet asserts that since insufficient time exists to review capital additions with the degree of care normally allowed in GRCs, such capital addition costs should be reviewed in the next GRC subject to two limitations. First, any plant the Commission excluded in the past from rate base should remain excluded. Second, Aglet recommends that capital additions made since the last GRC must be subject to refund until reviewed in the next GRC or alternatively the Commission should substantially reduce the allowed cost of capital to reflect elimination of the risk of disallowance.

3. TURN

TURN proposes that the Commission make all capital additions subject to reasonableness review in PG&E's next GRC. However, TURN also advocates for a cap now on the amount of capital additions that may be recovered. Costs that exceed the cap could be recovered in the next GRC after a reasonableness review. Due to PG&E's financial condition, TURN would allow PG&E to expense capital additions up to the cap (except hydro relicensing which would be capitalized).

4. Discussion

PG&E's testimony offers a summary description of its capital additions. Insufficient analysis exists to make a determination as to the reasonableness of PG&E proposed capital additions. PG&E should seek review of any capital additions in its next GRC. Any plant previously excluded from rate base should continue to be excluded. However, we wish to ensure that PG&E has the ability to make needed investments in its infrastructure. Therefore, we will accept PG&E's forecast of expenditures for capital additions, subject to balancing account treatment.

In establishing the balancing account, PG&E shall exclude capital additions previously excluded. Further, such capital additions shall be subject to reasonableness review in PG&E's next GRC. Such retrospective review of capital additions deviates from the traditional prospective review performed in GRCs, but such review is necessary to ensure that rates are just and reasonable.

E. Return on Rate Base

PG&E did not make a cost of capital showing in this proceeding. Instead, PG&E calculates its return on rate base, by using the ROE authorized in D.00-06-040 which results in a corresponding 9.12% return on rate base. Although some parties argued for a reduced return on rate base due to perceived changes in risk, no party made a comprehensive cost of capital showing.[14]

We recognize that PG&E is in Chapter 11 in bankruptcy court; thus, it is premature to reduce the ROE. Consequently, the ROE authorized in D.00-06-040 should be used until we consider modifications in PG&E's next cost of capital proceeding, GRC, or other appropriate proceeding.

F. Purchased Power Costs

1. PG&E

PG&E proposes a 2001 revenue requirement for Purchased Power Costs of $4.195 billion in scenarios one and three; and $1.321 billion in scenario two.[15] PG&E's scenarios one and three, each totaling $4.195, are for all of 2001. PG&E's scenario two, totaling $1.321 represents an eight-month time period from May to December 2001.

PG&E seeks recovery of costs of associated with power purchases from third parties, including the costs of power and related services procured under Qualifying Facility (QF) power purchase agreements (PPAs), bilateral power purchase contracts with various entities, including northern California

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14 We do adjust PG&E's O&M revenue requirement to account for reduced risk, as discussed previously.

15 See Exhibit URG-34. PG&E revised its proposal pursuant to D.01-05-015 to reflect a switch from gas-based pricing for some QFs to 5.37 cents/kilowatt-hour (Kwh) pricing.

irrigation districts, and FERC-approved tariffs with the California Independent System Operator (ISO).

PG&E estimates average QF costs of approximately $169 million per month from June through December 2001. PG&E's estimate makes certain assumptions about forward gas prices. Further, PG&E states that it will not accrue ancillary services costs because of its non-creditworthy status. PG&E proposes to adjust its revenue requirement monthly to reflect actual QF costs. PG&E states that its QF costs[16] vary significantly on a month-to-month basis because gas prices, which affect QF costs, have been highly volatile.

PG&E's bilateral power contracts are fixed-price, multi-year contracts. PG&E also holds long-term power purchase contracts with a number of irrigation districts and an integration contract with the Western Area Power Administration. PG&E estimates that the cost of these contracts should average approximately $14 million per month from June through December 2001.

PG&E's estimates of ISO-related costs are limited to the grid management charge (GMC) assessed by the ISO. PG&E states that GMC charges average $8 million per month from June through December 2001. However, PG&E states that the pending litigation by the ISO may require PG&E at some point to pay additional costs to the ISO or any other party for whom the ISO acted as agent.[17] Consequently, PG&E proposes that ISO costs be adjusted and updated monthly to reflect actual costs.

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[16] PG&E explains that it pays California QFs a capacity payment (pursuant to the terms set forth in the PPA) and an energy payment according to a Short Run Avoided Cost (SRAC) formula. PG&E states that the SRAC energy payment varies monthly depending on the price of 30-day gas delivered to California.

[17] PG&E states that it accrued more than $500 million in ancillary service charges for the month of January 2001. During that month, PG&E's credit rating was downgraded below investment grade. PG&E also asserts that in February 2001, FERC ordered that

Footnote continued on next page

2. ORA

ORA estimated purchased power costs of $1.678 billion for the 12-month period of July 2001 to June 2002. ORA states that its estimate differs significantly from PG&E's initial testimony because PG&E included the first three months of year 2001, which ORA contends were extraordinary months for utilities' purchased power costs. ORA maintains that the first half of 2001 was a time of unprecedented wholesale power costs and gas price levels in California. ORA asserts that the appropriate time period to consider for purposes of forecasting the utilities' interim revenue requirement should at least start from July 2001 to avoid inclusion of abnormal monthly patterns and cost conditions.

ORA's July 2001 to June 2002 revenue requirement forecast includes payments for QF energy and capacity as well as QF restructuring payments and administrative and legal costs. For SRAC-based QF costs, ORA states that it used gas price forecast assumptions which consider the most recent (July 2001) gas prices.

ORA recommends that PG&E's QF cost testimony be given no weight because PG&E has not met its burden of proof for the proposed costs relied upon in its testimony. ORA believes that PG&E's calculation of gas costs relies on unreasonable high actual and forecast costs. In addition, ORA asserts that PG&E provided insufficient breakdown of its aggregate forecast numbers to verify its proposed QF costs.

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the ISO cannot purchase ancillary services on behalf of non-creditworthy entities. PG&E does not meet ISO creditworthiness requirements and therefore cannot be responsible for ancillary services provided in ISO markets. The ISO sought rehearing on the order; its motion was denied.

ORA also believes that an inconsistency exists concerning whether PG&E estimates of QF costs include back payments to QFs. ORA states that due to a lack of a detailed breakdown of QF costs, ORA is unable to verify PG&E's inclusion or non-inclusion of unpaid amounts on QF energy deliveries.

ORA agrees with PG&E's estimate of costs for its bilateral and long term purchased power contracts.

ORA estimates ISO charges to be about $4.3 million per month. ORA bases its estimate on recent information contained in PG&E's Transition Revenue Account monthly reports filed with the Commission on GMC costs. ORA states that PG&E has no support for its $8 million per month estimate for ISO charges which only include GMC assessed by the ISO against all loads.

ORA opposes PG&E's proposal to update and adjust ISO costs monthly to reflect actual costs. Until such time as any additional ISO costs are mandated by a court, ORA asserts these costs should not be borne by ratepayers.

3. TURN

TURN recommends using the most recent gas price and electricity market price forecasts in establishing a revenue requirement for purchased power costs. TURN contends that PG&E is using very high price forecasts for fuels and electric commodity energy when compared to current market conditions, which will led to an overstated purchased power revenue requirement. Although, these forecasts will be trued up to actual costs, TURN asserts that the result of these high forecasts is to leave less room for DWR to collect needed revenues without a rate increase.

TURN specifically recommends that the Commission obtain and take official notice of the latest available futures prices for California gas. TURN believes that this step is reasonable and will assure that the best QF cost estimates are used to develop revenue requirements. TURN expects that use of these updated figures would reduce California ratepayers' bills for URG.

TURN also recommends that revenues PG&E receives from the ISO or DWR for Reliability Must Run (RMR) services should be subtracted from costs for PG&E-owned generation costs.

TURN generally agrees with PG&E's proposal to adjust QF and interutility contract payments to actual expenses, although lower gas price forecasts should be used. TURN also states that the Commission needs to maintain a bright line between the past and the future. TURN states that payments of past debts to QFs should not be not recoverable in PG&E's URG revenue requirement. TURN recommends that the Commission make its order clear that the only actual expenses eligible for recovery as a cost of URG are payments to QFs for payments made in the ordinary course of business for QF power after the URG rate is established.

TURN agrees that reasonable costs of ancillary services should be recoverable from ratepayers as a cost of generation. However, if DWR pays for ancillary services, such costs should be considered DWR costs. If PG&E pays for such costs, then such costs should be considered as part of PG&E's URG revenue requirement. TURN also maintains that ancillary service costs should be lower than PG&E's estimate, since the recent decline in market prices for energy can be expected to affect ancillary services markets as well.

TURN expects that PG&E should be providing significant amounts of its own ancillary services and should only have to purchase a small amount due to PG&E's hydro assets. Prior to the run-up in energy prices, TURN estimated that PG&E's hydro facilities would provide about $50 million in ancillary service revenue. TURN believes that PG&E may actually have surplus ancillary services for sale from its URG at certain times of day and of the year. If so, any payments or credits for that surplus made to PG&E by DWR should become a revenue credit, which should flow through to ratepayers.

TURN believes that the provision of ancillary services and the scheduling and dispatch of PG&E's URG should remain subject to reasonableness review because it affects the quantity, timing, and cost of the net short that must be purchased by DWR.

4. Aglet

Aglet opposes the recording of contract costs in any balancing account that would allow post-freeze recovery of costs incurred during the rate freeze. Aglet believes that PG&E should bear the undercollection risk through the end of the rate freeze.

5. Discussion

General agreement exists that purchased power costs should be subject to balancing account treatment. The primary issue we address here is the time period to use in forecasting a revenue requirement for QF costs. PG&E's scenarios one and three rely on actual gas prices in early 2001 to forecast QF costs, while TURN and ORA advocate using later gas prices to forecast QF costs.

Gas prices in early 2001 were abnormally high. PG&E has not offered any convincing evidence to support a finding that the gas prices seen in early 2001 represent a continuing trend. Rather, PG&E's updated forecast through 2002,[18] provides evidence that gas prices are declining. ORA's July 2001 to June 2002 time period should be used in adopting a gas forecast for QF

[18] Table 4 in Exhibit URG-34.

purchases since it omits abnormally high gas prices from early 2001. ORA's time period is also preferable to using projected prices for all of 2002 (from PG&E Exhibit URG-34) because it represents a near-term forecast and is less likely to be erroneous. PG&E's gas prices for the time period July 2001 to June 2002[19] should be used to calculate a revenue requirement since PG&E's gas prices were determined later than ORA's and are therefore more up-to-date.[20]

Past QF costs should be excluded from PG&E's QF revenue requirement since the scope of this decision is limited to establishing prospective cost-based revenue requirements. To the extent the revenue requirement we adopt contains past QF costs, PG&E should not record such costs in its balancing account.

Parties have not contested PG&E's estimate of costs for its bilateral and long-term purchased power contracts. We will use PG&E's estimated costs from PG&E's Exhibit URG-34 for the time period July 2001 to June 2002 for developing a revenue requirement for the year 2002.

PG&E's projected ISO and ancillary charges of $8 million per month are double ORA's average of about $4 million per month. PG&E's estimated ISO charges and ancillary services costs from PG&E's Exhibit URG-34 should be adopted for the time period July 2001 to June 2002. Ratepayers will be protected because recorded costs will be trued up against the forecasted revenue

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[19] From PG&E's Exhibit URG-34.

[20] For instance, PG&E's numbers reflect changes due to D.01-05-015, which allows QFs to elect a fixed price of 5.37 cents/Kwh.

requirement. By adopting PG&E's larger estimate, we ensure that the revenue requirement we adopt is sufficient to cover PG&E's ISO and ancillary charges.

PG&E's URG revenue requirement should reflect only actual costs paid by PG&E. To the extent DWR pays for ISO charges or ancillary services, PG&E should not record such costs in its balancing account. Also to the extent PG&E receives revenues for RMR or ancillary services it provides, such revenues should be credited to the appropriate balancing account.

For the calendar year 2002, an interim purchased power revenue requirement of $1.830 billion ($1.810 billion plus $20 million for Franchise Fees and Uncollectibles (FF&U)) should be adopted. This forecast corresponds to a July 2001 to June 2002 gas forecast summation as presented in Table A-Attachment 4 of PG&E's late filed Exhibit URG-34.[21]

G. Electric Energy Transaction Administration

EETA expenses include the costs of activities associated with purchasing electricity from the market, purchasing electricity under contracts with QFs and under other power purchase agreements, and managing PG&E's owned generation. PG&E proposes a 2001 revenue requirement of $30 million for EETA in scenarios one and two, and $31 million in scenario three.[22]

In section V.B.4, we adopted PG&E's proposed rate base of $53 million for EETA after finding the amount uncontested. In section V.A.5, we accepted,

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[21] PG&E presents a 12-month forecast for 2001 and a 12-month forecast for 2002. The last six months of 2001 and first six months of 2002 were added together to yield a revenue requirement of $1.810 billion. In addition, 20 million was included for FF&U.

[22] In scenario three, PG&E claims an additional $1 million in depreciation compared to scenarios one and two. PG&E's testimony does not clearly explain this difference.

subject to balancing account treatment, PG&E's forecast of $25 million in total operating expenses for EETA. Since it will be subject to true-up, we will accept EETA revenue requirement of $30 million contained in PG&E's second scenario.

H. Table 1 – Adopted URG Revenue Requirement for PG&E

PACIFIC GAS AND ELECTRIC COMPANY
(Millions)

Line No.	Description	Fossil and Hydro	Diablo Canyon	Purchased Power Costs[1]	Energy Transaction Administration[2]	Total Generation
		(a)	(b)	(d)	(e)	(f)
1	**REVENUE REQUIREMENT:**	622	393	1,830	30	2,875
	OPERATING EXPENSES:					
2	O&M Expenses*	283	273	1,810	13	
3	Administrative and General	79	32	-	4	
4	Uncollectibles	2	1	5	0	
5	Franchise Requirements	5	3	15	0	
6	Subtotal Expenses:	369	309	1,830	17	
	TAXES:					
7	Property	13	3	-	1	
8	Payroll	4	11	-	1	
9	Business and Other	0	-	-	0	
10	State Corporation Franchise	7	(4)	-	0	
11	Federal Income	25	(19)	-	2	
12	Total Taxes	49	(9)	-	4	
13	Depreciation	125	56	-	4	
14	**Total Operating Expenses**	543	356	1,830	25	
15	Net for Return	79	37	-	5	
16	Rate Base	985	408	-	53	

* O&M Expenses are reduced by 2.168% to adjust for no reasonableness review, ~ 130 basis point reduction in equity. [i.e. 0.0130=.48, ROE X (985, RateBase) X (289, Op.Exp.*.021268)]

[1] Purchased Power costs include payments made under QF contracts, Bilateral contracts, and Ancillary Services agreements.

[2] Electric Energy Transaction Administration costs include the costs of activities associated with purchasing electricity from the market, purchasing electricity under contracts with QFs and under other power purchase agreements, and managing PG&E's retained generation portfolio. They do not include commodity costs.

VI. Edison

A. Summary

Edison's URG proposal consists of native load or Edison-owned generation (nuclear, hydro, and coal), QF Contracts, interutility contracts and bilateral forward contracts. Edison also proposes revenue requirements for ISO charges and for payments to the Department of Water Resources (DWR). We do not address DWR's revenue requirement here since the matter is being specifically addressed in a separate phase of this proceeding.[23]

Edison proposes the following URG revenue requirement for 2002:

($ millions)

Fossil and Hydro[24]	$ 470
Nuclear	842
QF Contracts	2,102
Interutility Contract	230
Bilateral Forward	108
ISO Charges	68
Total	**$3,820**

[23] On January 8, 2002, the Commission issued a draft decision in a different phase of this proceeding which addresses DWR's revenue requirements. In. D.02-__-___, the Commission issued a final decision adopting revenue requirements for DWR.

[24] See Joint Comparison for a summary Edison's fossil, hydro and nuclear revenue requirements.

TURN and Aglet do not propose a specific URG revenue requirement for Edison, but instead make policy recommendations for establishing a URG revenue requirement. ORA proposes the following URG revenue requirement for Edison based on the time period July 2001 to June 2002:

(Millions of Dollars)

Fossil[25]	$335
Hydro	122.2
Nuclear	796.1
Purchased Power[26]	
QF Contracts	2,031
Interutility Contract	148
Bilateral Forward	108
Other[27]	1.4
Total	**$3,541.7**

In addition, Edison proposes to establish four new balancing accounts for implementing its URG revenue requirement and a fifth balancing account to track past undercollections. Edison requests implementation of its URG revenue requirement and proposed balancing accounts because significant regulatory changes have impacted its generation revenue requirements and associated

[25] See Exhibit URG-25, revised Table 6-1.

[26] See Exhibit URG-32.

[27] See Exhibit URG-25, revised Table 6-1. Other costs include unallocated costs.

ratemaking.[28] Edison's proposal for creating of new balancing accounts is addressed in Section IX.

B. Non-Nuclear Generation

1. Edison

Edison states that its URG revenue requirement will include:

- Actual on-going operating costs for Palo Verde, Mohave, Four Corners, and Catalina;[29]
- Authorized on-going operating costs for Hydro; and
- Actual capital costs, including a full return on Edison's generation rate base.

Edison proposes to value its generation assets at the net book value of the assets on December 31, 2000, including flow through taxes, subject to refund with respect to post-1995 capital additions. Edison also proposes to record in a balancing account any capital additions placed in service after January 1, 2001, subject to refund based upon subsequent Commission determination of reasonableness of such investments. Edison uses depreciation and amortization schedules based on the expected remaining life of each plant.

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[28] Edison cites (1) legislation requiring it to retain its generating assets (AB X1-6); (2) the FERC's elimination of the requirement that Edison must buy and sell all of their energy requirements through the PX; and (3) the January and March 2001 Commission decisions that adopt rate surcharges.

[29] Edison's generation-related operating expenses include: (1) fuel and fuel carrying costs; (2) emission credit costs; (3) direct O&M and A&G(4) Customer Service and Information; (5) indirect A&G; (6) taxes; (7) scheduling and dispatch costs; (8) contract administration; and (9) congestion costs.

a) Mohave

The Mohave Generating Station, located in Laughlin, Nevada, is a coal-fired resource operated by Edison. Edison states that the plant has an operating capacity of 1,580 MW, of which Edison owns 56%, or 884.8 MW. In 2002, Edison estimates that Mohave will operate at a capacity factor of 73%, and produce 5,660 GWh. Edison's forecast of Mohave generation relies upon recent operating history of the plant, recognizes a planned outage in 2002 and an allowance for unplanned outages.

Edison estimates operating costs for 2002 as $155.467 million. Edison's capital-related forecast, including recovery of the remaining December 31, 2000 plant balance over Mohave's remaining life of 16 years is $23.903 million. Edison's total revenue requirement for Mohave for 2002 is $179.370 million.

b) Four Corners

The Four Corners generating station is a coal-fired plant located in Fruitland, New Mexico. APS operates the plant and Edison owns 753.6 MW, or 48% of Units 4&5. Edison's 2002 generation forecast relies upon recent operating history and a planned outage for Unit 5 scheduled in early 2002. Edison forecasts a capacity factor of 79%, which results in production of 4,687 GWh. Edison's cost forecast relies upon recent recorded history and APS's outage and budget data. Edison's operating forecast for 2002 is $119.669 million. Edison's capital-related forecast, including recovery of the remaining December 31, 2000 plant balance over Four Corners remaining life of 15-years is $28.861 million. Edison's total revenue requirement for Four Corners for 2002 is $148.530 million.

c) Hydro

Edison assumes a "normal" year of precipitation and that the operating cost forecast for the hydroelectric plants for 2002 is $45.094 million, which is the same amount authorized in 1997 in D.97-12-102. Edison's capital-related forecast, including recovery of the remaining December 31, 2000 plant balance over the assets remaining life of 40 years is $83.827 million. Edison's total revenue requirement for hydro for 2002 is $128.876 million.

d) Catalina

The Pebbly Beach Generating Station is the sole source of electric generation on Catalina Island. The Generating Station's major equipment systems include six power generating units with a total capacity of 9,325 kW and a maximum dependable output of 6,525 kW. Edison's operating costs forecast for 2002 relies on recent trends and is $5.377 million. The capital-related forecast is $1.623 million. Edison's total revenue requirement for the Pebbly Beach Generating Station for 2002 is $7 million.

2. ORA

a) Operating Expenses

ORA accepts Edison's estimate of operating costs for fossil generation, except that ORA recommends that the Commission lower Edison's tax estimate.

For hydro generation, ORA recommends that the Commission use the lower of recorded costs versus Edison's $45 million forecast. ORA believes this method is consistent with achieving a cost-based revenue requirement since Edison did not perform a cost analysis but instead estimated its hydro generation revenue requirement by simply using the revenue requirement last adopted for hydro via a settlement in D.97-08-056.

b) Depreciation

ORA accepts Edison's approach to recover plant balances of the remaining lives of the fossil assets. ORA has not verified Edison's depreciation life for hydro but believes it to be reasonable.

3. TURN

a) Operating Expenses

TURN recommends using recorded costs for generation O&M through the end of 2002, subject to existing Commission ratemaking policies. TURN also recommends using Edison's cost-based proposals, excepting fuel prices, to set an initial revenue requirement, which should then be balanced against actual costs and reviewing recorded costs for reasonableness.

b) Rate Base

TURN recommends setting rate base equal to end-of-year 2000 book value including past capital additions and subtracting decommissioning costs previously recovered. This rate base would be the basis for depreciation, property taxes, return, and income taxes. Return, taxes, and depreciation related to capital additions not previously approved would be subject to refund in the event of disapproval in a reasonableness review.

In addition, TURN proposes using recorded costs for capital additions subject to a cap and reasonableness review. Costs above the cap would not be recoverable now but could be recovered in the next GRC after a reasonableness review. Due to Edison's financial condition, TURN proposes allowing Edison to expense capital additions up to the cap (except hydro relicensing which would be capitalized), including a gross-up for the net present value of income taxes.

c) Depreciation

TURN recommends using either an existing schedule of depreciable lives from Edison's most recent rate case covering generation plant (Test Year 1995) applied to the new year end-of-year 2000 rate base or the new plant lives proposed by Edison, whichever yields lower near-term rates, on an interim basis. TURN maintains that it is reasonable to defer establishment of new depreciation rates on a longer-term basis to the next rate case.

4. Aglet

a) Operating Expenses

Aglet recommends use of actual operating costs to develop a revenue requirement, except Edison hydro costs, subject to any overall rate limitation the Commission might order and subject to reduced ROE to reflect the loss of reasonableness review risk. Aglet accepts Edison's hydro costs for interim ratemaking purposes because they have been subject to Commission review.

b) Rate Base

Aglet recommends determination of capital-related costs based on recorded net book value of plant-in-service subject to two conditions. First, plant that the Commission has excluded from rate base in any prior proceeding must remain excluded. Second, either rates that include plant additions since the last Commission review must be subject to refund until the next general rate case (Aglet's preferred approach), or the allowed cost of capital must be substantially reduced to reflect elimination of the risk of disallowance.

Aglet recommends reasonableness review, including need and prudency of incurred costs, of capital additions made since the last comprehensive Commission review. Aglet does not oppose Edison's suggestion that such review be made in the next general rate case.

c) Depreciation

Aglet recommends that depreciation lives should be the same as those adopted in Edison's last general rate case, for the same asset categories.

5. Discussion

a) Operating Expenses

Many of our concerns about the reliability and accuracy concerning PG&E's URG revenue requirement proposal also apply to Edison's revenue requirement proposals. Although Edison provided more cost information than PG&E, little examination of the reasonableness or accuracy of such costs occurred. Edison also has similar concerns about the accuracy of its projected costs and recommends interim treatment pending a full cost of review in its Test Year 2003 GRC. We agree with Edison and intervenors that the URG revenue requirement we adopt for Edison in this decision should be interim.

Edison's proposal to use actual costs, except for hydro, to develop a URG revenue requirement mitigates our concerns about the reliability and accuracy of Edison's proposed URG revenue requirement. However, we will go one step further and apply the same approach to Edison's hydro generation, consistent with the TURN cost recovery proposal. Adoption of the TURN cost recovery proposal ensures fair treatment for both Edison and ratepayers. Under the TURN cost recovery proposal, Edison should recover all of its reasonably incurred URG costs on a going forward basis and Edison's customers should pay cost-based rates.

Given the interim nature of the revenue requirement and strain placed on parties' resources (in light of upcoming GRCs), we agree with Aglet's concerns that the work necessary to review the reasonableness of O&M costs may outweigh the savings benefits to consumers.

Consequently, as an interim measure, reasonableness review for Edison's O&M costs for fossil and hydro generation should be suspended. By suspending reasonableness reviews for Edison's O&M costs for fossil and hydro generation, we reduce Edison's financial risk by guaranteeing the recovery of recorded costs. We further agree with Aglet that this reduction in risk should be accompanied by an equivalent reduction of Edison's URG revenue requirement. Consistent with Aglet's analysis, we find that Edison's proposed revenue requirement of $470 million for fossil and hydro generation should be reduced by $2 million to account for the suspension of reasonableness review for O&M expenses.

b) Rate Base

Edison did not provide sufficient information to verify its rate base amount. Edison also offered very little specific analysis in its testimony on capital additions.

In its next GRC, Edison should present detailed testimony to support its rate base, capital additions and requested return on rate base. Rate base should be determined using recorded net book value of plant-in-service as of December 31, 2000. We will also accept Edison's projected capital addition costs for purposes of establishing an interim URG revenue requirement. However, under the TURN cost recovery proposal, these costs should be recorded for reasonableness review in Edison's next GRC or similar proceeding. We reject TURN's proposal to create a cap for capital expenditure or to allow Edison to expense its capital additions.

Edison requests approximately $106 million as return on rate base. Below in section VI.F, we address rate of return for both non-nuclear and nuclear generation.

c) Depreciation Lives

Edison's use of depreciation and amortization schedules based on the expected remaining life of its non-nuclear generation plant is reasonable.

C. Nuclear Generation

1. Edison

a) SONGS

Edison operates and co-owns 75.05% of SONGS 2&3. Edison assumes a capacity factor of 88%, a 45-day spring 2002 refueling for Unit 2, and an allowance for unplanned outages at both units. Edison uses an ICIP price of 4.15 cents/kWh, plus an A&G adder of 0.21 cents/kWh, resulting in a 2002 forecast of $545 million. In addition, Edison uses a 10-year amortization period for the remaining December 31, 2000 plant balance, and estimates the capital-related cost as $104.408 million. Edison states that its combined O&M and capital-related forecast costs for San Onofre Nuclear Generating Station (SONGS) 2&3 in 2002 are $649.408 million.

b) Palo Verde

Edison owns a 15.8% share (590 megawatts (MW)) of Palo Verde Nuclear Generating Station, which is operated by Arizona Public Service (APS) Company. Edison's forecast, relying upon "recent experience," assumes one refueling in 2002, and an allowance for forced or unplanned outages for an expected site capacity factor of 88% or 4,550 gigawatt hours (gWh) (Edison's share).

Edison used APS's budget, adjusted for certain Edison costs such as scheduling and dispatching, which results in a forecast of $118.325 million. In addition, Edison used a 10-year amortization period for the remaining December 31, 2000 plant balance, which Edison contends results in capital-related costs of $64.122 million. Edison estimates that the total Palo Verde cost for 2002 is $182.447 million.

2. ORA

ORA accepts Edison's SONGS ICIP calculation. However, ORA recommends recovery of nuclear sunk costs over the remaining useful life of SONGS and Palo Verde based on their remaining Nuclear Regulatory Commission (NRC) license period. ORA also recommends that Edison continue use a rate of return for SONGS and Palo Verde of 9.49% for 2002. ORA maintains that the Commission should use the lesser of recorded O&M and A&G expenses versus Edison's 2002 forecast of Palo Verde's O&M and A&G expenses.

3. TURN

a) Initial Revenue Requirement

TURN proposes using Edison's forecast for Palo Verde to set an initial revenue requirement, but to true-up the adopted forecasts with actual recorded costs. However, for SONGS, TURN argues that the initial ICIP price should be reduced by 20% or instead use an average of 1999-2000 recorded costs as the starting point, since ICIP has exceeded the actual operating costs. TURN would set rate base equal to end-of-year 2000 book value (exclusive of capital additions incurred since establishment of ICIP, and subtracting decommissioning costs previously recovered). TURN recommends depreciation of any remaining book value over the remaining life of the plants on an interim basis (15 years for SONGS, 23 years for Palo Verde). In addition on an interim basis, TURN supports a NUIP for SONGS similar to that provided for Palo Verde for all fuel cycles beginning after the end of the ICIP period. Under this plan, the utility would receive one-half of the difference between replacement power costs and nuclear fuel costs for output in excess of 80%, with replacement power costs capped at 5 cents/kWh.[30]

b) Elimination of ICIP

TURN advocates that the Commission should eliminate ICIP and replace this incentive approach with cost-based pricing. TURN argues that ICIP pricing is inconsistent with Section 360.5 and D.01-06-041.

In relevant part, Section 360.5 states in relevant part:

> The commission shall determine that portion of each existing electrical corporation's retail rate effective on January 5, 2001, that is equal to the difference between the generation related component of the retail rate and the sum of the costs of the utility's own generation, qualifying facility contracts, existing bilateral contracts, and ancillary services. That portion of the retail rate shall be known as the California Procurement Adjustment. (Emphasis added.)

TURN also argues that the Commission should reject arguments that any modification to ICIP pricing would violate Section 367(a)(4) which addresses transition cost recovery and states in relevant part:

…

> (4) Nuclear incremental cost incentive plans for the San Onofre nuclear generating station shall continue for the full term as authorized by the commission in Decision 96-01-011 and Decision96-04-059, provided that the

[30] The cap does not presently exist in the NUIP adopted by the Commission, but has been proposed in recent comments TURN filed in A.96-02-056, and seemed to be agreed to by Edison and ORA in subsequent comments.

> recovery shall not extend beyond December 31, 2003. (Emphasis added.)

TURN contends that Section 367(a)(4) only limits the Commission's ability to change the "term" of the "cost incentive plan," but does not limit the Commission's ability to modify the price set under the plan.

TURN also advocates for rejection of Edison's proposal for a 10-year amortization period for its net book value in SONGS and Palo Verde. TURN contends that Edison has offered no solid support in this phase for a 10-year amortization period.

4. Aglet

Aglet recommends that ICIP ratemaking cease for SONGS and argues that the profit sharing element of ICIP goes beyond utility cost. Aglet agrees with TURN that enacted Pub. Util. Code § 360.5 restricts recovery to actual incurred costs.

5. Discussion

We agree with Aglet, TURN and ORA that ICIP ratemaking should be modified. Significant changes in law, market and regulatory environment have occurred that warrant eliminating or modifying ICIP to produce a cost-based rate. We agree with TURN's analysis that pursuant to Section 360.5, the Commission may pursue cost-based pricing for nuclear generation. In D.01-01-061, we also placed all utilities on notice that URG should be cost-based. Most importantly, TURN's proposal ensures that Edison suffers no harm or taking since TURN's cost recovery proposal allows Edison to recover all of its actual and reasonable costs incurred for its nuclear generation on a going forward basis.

However, the record is insufficient to determine the exact revenues necessary to reflect Edison's actual nuclear generation costs. Therefore, we will also adopt as a placeholder and subject to true-up against actual recorded costs, Edison's proposed revenue requirement of $842 million for nuclear generation. We will not adopt TURN's request to modify the initial starting point revenue requirement by reducing the SONGS ICIP by 20%. Even though we anticipate that this revenue requirement may exceed Edison's actual costs for its nuclear generation, we want to ensure that Edison suffers no shortfall. However, ratepayers will be protected when Edison records its actual costs, and any difference is amortized and reflected in rates. Since we have modified Edison's method of recovering its costs, from ICIP to recorded costs, we will make all nuclear generation costs, including O&M, subject to reasonableness review.

TURN and Aglet both raised concerns about the depreciation lives. Given the limited record, we will accept Edison's depreciation lives for nuclear generation. In Edison's next GRC, we will revisit the issue of depreciation lives.

D. Purchased Power

1. Edison

a) QF Payments

Edison states that it purchases electricity from approximately 320 QFs and makes energy and capacity payments for the electricity they deliver. Edison also makes payments under a number of other agreements providing for the restructuring of QF contracts. Edison expects that the majority of the remaining 320 QFs will sign a settlement agreement resolving litigation associated with payments for their past deliveries. The settlement agreement leaves in place the existing capacity payments and addresses the SRAC of energy for those QFs whose contracts mandate that the energy pricing shall be the Commission-approved SRAC prices.

For the calendar year 2002, Edison forecasts its QF purchases and QF restructuring payments to be approximately $2.338 billion.

b) Bilateral Contracts

(1) Interutility Contracts

Edison entered into 11 long-term purchase, sale, and exchange agreements (interutility contracts) that began on or before the startup of the ISO and PX markets on March 31, 1998. Edison's testimony describes in general the type of contract costs that Edison may incur and the revenues that Edison may receive. Edison forecasts net cost for interutility contracts to be $230.396 million for calendar year 2002 associated with 563 GWh of net outflow from Edison.

(2) Bilateral Forward Contracts

Edison states that it entered into various bilateral forward contracts during the period spanning November 15, 2000 to January 8, 2001. Edison states that a majority of these contracts have been liquidated due to Edison's financial situation. Edison states that it may also incur other associated costs including credit and collateral and contract administration costs associated with the bilateral forward contracts. Assuming no further liquidation, Edison forecasts the total bilateral forward procurement cost for the July 1, 2001 to December 31, 2002 period to be approximately $160 million and on an annualized basis, Edison forecasts the procurement cost to be approximately $106 million.

2. ORA

ORA proposes revenue requirements for Edison of $2.03 billion for QFs, $148 million for interutility contracts, and $108 million for bilateral contracts. ORA's recommendation is based on the 12-month period July 2001 to June 2002.

Although Edison presented two purchased power revenue requirement scenarios based on its credit status: (1) "non creditworthy" and (2) "creditworthy," ORA only addressed Edison's first ("non creditworthy") scenario.

a) QF Contracts

ORA reviewed Edison's inputs[31] for developing its QF energy payment forecast. ORA also used the same SRAC payment formulas that Edison used in developing its QF energy payment revenue requirements. ORA's review took into account D.01-06-015, the recently approved QF pricing agreement between Edison and the California Cogeneration Council. ORA states that prior to the effective date of the agreement, it was reasonable for Edison to base SRAC energy payments to QFs on the formula previously approved in D.01-03-067.

ORA forecasts SRAC energy payments of $2.03 billion compared to Edison's forecast of $2.27 billion. ORA's attributes the $240 million difference partly to use of a slightly different gas price forecast.

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[31] Incremental Energy Rate (IER), spot gas pricing, O&M adder value, and the line loss factor.

ORA's reviewed Edison's estimate of $0.6 billion for QF capacity payments and ORA states that the estimate compares favorably to historical levels.

b) Interutility Contracts

ORA's analysis finds that Edison's estimated revenue requirements of $148 million for its interutility contracts during the July 2001 to June 2002 period is reasonable. ORA states that this revenue requirement reflects the combined net estimate of interutility costs ($224 million) against the projected revenues accruing to Edison from the various counterparties to these contracts.

c) Bilateral Contracts

ORA finds as reasonable, Edison's annualized estimate of approximately $108 million for its bilateral forward contracts for the July 2001 to June 2002 period. ORA bases its finding on a comparison review of Edison's estimates with confidential information filed by Edison with the Commission on its bilateral contracts.

3. TURN

TURN supports balancing account treatment of contract costs with the caveat that lower gas price forecasts should be used to set the associated revenue requirement. TURN states that only actual expenses made in the ordinary course of business for QF power should be recoverable. TURN opposes inclusion of payments for past debt in Edison's URG revenue requirement. TURN opposes the proposal of the CAC to recover unpaid QF obligations in Edison's URG revenue requirement.

4. Aglet

Aglet opposes the recording of contract costs in any balancing account that would allow post-rate freeze recovery of costs incurred during the rate freeze. Aglet states that such costs should continue to accrue in Edison's TCBA to ensure that Edison bears the undercollection risk through the end of the rate freeze.

5. Discussion

General agreement exists that Edison's purchased power costs should be subject to balancing account treatment. Edison provided monthly cost estimates for its bilateral and long term purchased power contracts. To be consistent with our treatment of PG&E and SDG&E, we will adopt a revenue requirement for QFs, bilaterals and interutility contracts using the timeframe of July 2001 through June 2002.

The forecast period July 2001 through June 2002 should more accurately forecast Edison's purchased power revenue requirement since purchased power costs depend heavily on gas prices and using a more recent forecast period will better reflect the revenue requirement needs of Edison. Using this time period adjusts Edison's purchased power revenue requirements, including FF&U, from $2.440 billion for all of 2002 to $2.425 billion.[32]

Similar to PG&E, we preclude recovery of past QF costs in Edison's purchased power revenue requirement. To the extent that past QF costs are contained in Edison's revenue requirement, Edison should not record such amounts in its balancing account.

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[32] The revenue requirement increases due to QF buyouts occurring in July and October 2001.

E. ISO-Related Charges

1. Edison

Edison asserts that the ISO assesses numerous market and administrative charges upon Edison's load and generation. Edison asserts that it cannot precisely project the amount or type of ISO-related charges that it may incur prior to 2003 due to its credit status. Edison proposes to record all ISO-related charges in a balancing account.

Nonetheless, Edison projects annual costs associated with Edison's retail bundled load and retained generation and contracts for (1) Edison's total ancillary services requirements,[33] and (2) ISO "uplift" charges. Additionally, Edison allocated such costs between Edison and the DWR, depending on whether Edison is an investment grade entity.

a) Ancillary Services Cost Projection

Due to the lack of liquid forward ancillary services markets, Edison states that it cannot offer a sophisticated analysis of costs. However, Edison does attempt to estimate its total annual ancillary services costs for 2002, using a "crude" forecasting approach that relies upon the most recent six-month period to forecast 2002 annual ancillary services. Edison does not address whether it is responsible for all, a portion, or none of such costs. Edison forecasts 2002 ancillary costs of zero under a "non creditworthy" scenario and $486.8 million under a "creditworthy" scenario.

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[33] Ancillary services under ISO control consist of spin, non-spin, regulation up and down, and replacement reserve.

b) ISO Uplift Charges

Again, due to the numerous uncertainties that exist with many of the ISO's charges, Edison states that it cannot offer a sophisticated analysis of ISO uplift charges do not include ancillary services and energy charges, but makes a rough estimate of its total annual ISO uplift charges for 2002. Edison does not address whether it is responsible for all, a portion, or none of such costs. Edison projected total annual ISO uplift charges of approximately $68 million, under its "non creditworthy" scenario and $740 million under its "creditworthy" scenario.

c) Allocation of ISO-Related Charges Between Edison and DWR

Edison proposes to allocate to both Edison and DWR[34] any ISO charges for ancillary services and other uplift charges billed to Edison as the scheduling coordinator for its controlled generation and bundled load. Edison asserts that the allocation methodology is dependent on the creditworthiness of Edison, pursuant to FERC Orders.

While Edison is a non creditworthy entity, Edison asserts that the ISO may not purchase energy or ancillary services from a third-party on behalf of Edison. Instead, Edison asserts that the ISO has identified DWR as the only creditworthy buyer. Therefore, Edison asserts DWR must purchase 100% of the ancillary services billed to Edison while Edison is non-creditworthy. Edison contends that DWR should pay approximately 80% of the uplift charges while Edison pays the remaining 20%.

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[34] Edison proposes to allocate charges to DWR while DWR is providing energy to Edison's bundled customers.

Even when Edison becomes creditworthy, Edison contends that DWR retains the responsibility to cover the costs of Edison's forecasted net-short position. Under such circumstances, Edison proposes allocating ancillary services and uplift charges to DWR based on a percentage of the actual total charges associated with Edison's bundled retail load. Based on current load and net-short forecasts, Edison forecasts that DWR will be providing 32% of Edison's bundled retail load in 2002, and will therefore be responsible for 32% of the ISO-related charges.

2. ORA

ORA reviewed Edison's requested revenue requirement of $68 million to pay the ISO for certain uplift charges which apply regardless of its credit standing. ORA states that these uplift charges consist of a number of different charges such as UFE, GMC, neutrality, congestion, wheeling, interest and penalties. ORA reviewed Edison's breakdown of uplift charges, and ORA agrees that it is difficult to forecast these charges. ORA states that Edison's forecasting method is acceptable, but requests an update to Edison's revenue requirement to consider April 2001 uplift charges and the July 2001 to June 2002 retail load estimates.

With respect to its ancillary services, ORA acknowledges Edison's statement that it is not currently paying for these services due to its credit status. However, ORA still disagrees with Edison's estimate of $740 million for ancillary services since Edison based the estimates on the period November 2000 through April 2001. ORA has concerns about whether Edison's numbers represent "actual" ancillary services costs already incurred during the most recent six months and "actual" bundled retail load, or if these numbers are estimates as well. If the latter, ORA complains that Edison gave no explanation as to how it developed its estimated numbers. ORA agrees with Edison concerning the "roughness" of Edison's forecasting method.

3. TURN

TURN supports recovery of reasonable ancillary costs as generation costs in Edison's URG revenue requirement. However, if such costs are paid by DWR, TURN contends that such costs should be excluded from Edison's URG revenue requirement. Further, TURN recommends that revenues received from the ISO and/or DWR for RMR or for ancillary services provided in excess of the requirements of native loads should be subtracted from Edison's generation costs.

As part of future reasonableness reviews, TURN would have the Commission examine the dispatch of hydro generation, the self-provision of ancillary services and sale of excess ancillary services from hydro into the markets. This review would assure that Edison's operations strive to minimize DWR's costs for spot market power, and utility and DWR costs for ancillary services.

4. Discussion

Similar to our treatment of other URG costs, Edison should record its ISO-related charges in a balancing account for recovery subject to reasonableness review. A revenue requirement of $68 million for ISO-related charges subject to balancing account treatment is reasonable for purposes of establishing Edison's interim URG revenue requirement.

We also agree with TURN's concern that Edison's URG revenue requirement should reflect only costs paid by Edison. To the extent DWR pays for ISO charges or ancillary services, Edison should not record such costs in its balancing account. Also to the extent Edison receives revenues for RMR or ancillary services it provides, such revenues should be credited to the appropriate balancing account.

F. Cost of Capital

Edison proposes a ROE of at least 11.6%. Edison did not make a cost of capital showing in this phase. In part, Edison relies upon an April 9, 2001 MOU between Edison International and DWR to justify its requested ROE.

1. TURN

TURN would set Edison's interim rate of ROE for retained fossil generation at 9.6%. TURN contends that this rate of return reflects the significant reduction in risk arising from the use of recorded costs and expensing of capital additions.

2. Aglet

Aglet recommends a ROE of 10% for Edison's generation operations. Aglet believes Edison's ROE should be less than Edison's proposed ROE of 11.6% which was authorized in 1997, because prospectively Edison faces less risk now than in 1997. For instance, Aglet states that DWR's procurement efforts have shifted undercollection risk from Edison to DWR..

Until the next cost of capital proceeding, Aglet recommends retention of currently authorized utility capital structures and costs of debt and preferred stock last approved by the Commission. Aglet recommends authorization of an interim ROE in the range of 9.0% to 11.0%, with a point estimate of 10.0%. Aglet asserts that the risks facing generation investors in 2001 and 2002 fall somewhere between restructuring risks prior to May 2000, when market prices skyrocketed, and distribution risks considered in the Commission's last authorized ROE for PG&E. Those risks produce an ROE range from 90% of the embedded cost of debt, which is roughly 8%, to 11.22%. Thus, Aglet believes a range of 9.0% to 11.0% is reasonable.

Aglet states that Edison's currently authorized 11.6% ROE for distribution operations is an artifact of its distribution performance-based ratemaking (PBR) mechanism. Further, Aglet states that the broad deadband in that mechanism makes it insensitive to changes in interest rates and other economic risks. In 1998, 1999 and 2000, PG&E and Edison investors faced very similar risks. Yet for those years the Commission authorized equity returns for PG&E, which does not have a distribution PBR mechanism, of 11.2%, 10.6% and 11.22%. (D.97-12-089, D.99-06-057, D.00-06-040.) Thus, Aglet reasons that Edison's 11.6% ROE has not fairly reflected distribution risks since 1997. Aglet rejects Edison reasoning that a ROE of at least 11.6% "is clearly indicated" by the recent memorandum of understanding (MOU) among Edison, Edison International and DWR. Aglet contends that no weight should be given to any cost of capital in the MOU since neither the Commission nor the Legislature has found the MOU to be reasonable. Further, because the Edison MOU is a settlement, Aglet contends that neither the principles nor the numbers in it can be relied upon as precedent.

3. Discussion

Edison’s last authorized ROE was set based on assumptions that have changed. We are concerned about ensuring that ROE is set at a level to attract capital investment and accelerate the improvement of Edison’s standing in the credit markets. However, Edison’s last authorized ROE was set in contemplation of potential risks related to competition and restructuring. Edison should receive a lower ROE than last authorized since the law and policies concerning divestiture and accelerated depreciation have changed. AB 6X now requires that utilities retain generation-related assets until at least 2006. Use of recorded costs to establish a revenue requirement means that Edison's investors face little to no risk of incurring large undercollections and not recovering actual costs. In addition, DWR has assumed most of the procurement risks that led to Edison's financial problems. Given these substantial changes in circumstances, we are obligated to assess Edison's ROE going forward.

In its testimony, Aglet compares the different risks associated with different utility operations (distribution, generation, and combined). In summary, the analysis demonstrates that given recorded cost treatment and DWR's assumption of procurement risk, Edison investors are entitled to a lower ROE. In light of the limited record but obvious changes to market risks that Edison faces, we seek to balance the interests of ratepayers and shareholders. Our approach is not as exact a review as occurs in a cost-of-capital proceeding, but instead reflects a pragmatic approach and makes pragmatic adjustments to Edison's ROE. Therefore, we agree with Aglet that Edison's authorized ROE should be reduced. As an interim measure, until Edison's next cost-of-capital or similar proceeding, we adopt Aglet's recommended ROE of 10% for Edison generation operations. The lower ROE translates into a rate of return (ROR) of 8.72% from a prior 9.49% ROR. The approximate dollar difference in Edison's revenue requirement is $10 million.

We recognize that the Commission recently entered into a settlement with Edison that was approved in Case No. 00-12-056-RSWL (Mcx) in United States District Court. That settlement explicitly acknowledged that one of its purposes was to restore the investment grade creditworthiness of Edison as quickly as possible. The actions we take today are in no way intended to interfere with this process. Instead, the reduced ROE balances both ratepayer and shareholder interests. Ratepayers should not have to pay for a return that is based on an ROE set when Edison faced competition. The cost-of-service ratemaking approach we adopt today reduces the risks to investors but should still allow Edison to maintain its financial integrity, attract necessary capital, and compensate investors for the risks assumed. Again, we recognize that in light of our expedited procedures, there was not the full showing normally done for cost-of-capital issues. We intend to re-examine this ROE in Edison's next cost-of-capital proceeding or GRC.

G. Table 2 – Adopted URG Revenue Requirement for Edison

SOUTHERN CALIFORNIA EDISON COMPANY
(000's)

Revenue Requirements		
	Generation	
1	Operating Expenses*	$987,205
2	Capital Related	
3	Depreciation	$102,506
4	Taxes	$55,827
5	Return **	$97,525
6	Gen.Plant	$42,271
7	Total	$1,285,334
8	W/ FF&U	$1,299,752
	Purchased Power*	
9	QFs	$2,130,162
10	Bilaterals	$106,364
11	Interutility	$161,255
12	Total	$2,397,781
13	W/ FF&U	$2,424,677
	ISO-Related Charges	
14	Ancillary Services	-
15	Uplift Charges	$67,214
16	W/ FF&U	$67,968
17	Total URG	$3,750,329
18	Total URG w/ FF&U	$3,792,397

* Operating Expenses have been reduced by 0.9277% to reflect suspended reas. review = ~ 105 basis point reduction in ROE. (Excludes SONGS and Palo Verde)

** Return adjusted to 8.72% ROR

*** Based on the July 20, 2001 DRI's gas price forecast for the period from July 2001 through June 2002.

VII. SDG&E's URG Revenue Requirement

A. SDG&E

SDG&E proposes a URG revenue requirement of $466 million. SDG&E's URG revenue requirement reflects costs for SONGS, a long-term power purchase agreement with Portland General Electric (PGE), QF contracts, and three three-year bilateral power purchase contracts totaling 125 MWs entered into at the end of 2000. SDG&E's proposed URG revenue requirement also includes costs for Other ISO Charges[35] and an ISO GMC.

SDG&E proposes a URG revenue requirement (based on July 2001 to June 2002 forecast numbers[36]) as follows:

	(millions)
SONGS	$154.132
PGE (Interutility)	46.457
Qualifying Facilities	129.475
Bilateral Contracts	62.910
Other ISO Charges	52.963
Grid Management Charge	19.923
Subtotal	$465.860

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[35] The key elements of "Other ISO Charges" in SDG&E's proposed revenue requirement are unaccounted for energy (UFE), neutrality adjustments and congestion charges

[36] See Exhibit URG-35.

SDG&E excludes generation costs from its proposed URG revenue requirement for which DWR has agreed to assume responsibility pursuant to a Memorandum of Understanding (SDG&E MOU) entered into between DWR, SDG&E and Sempra Energy dated June 18, 2001. SDG&E defines ISO charges as consisting of three primary components, (1) ancillary services, (2) "other ISO charges" and (3) GMC. Pursuant to the SDG&E MOU, SDG&E asserts that DWR has responsibility for paying the ancillary services component of ISO charges. Thus, SDG&E excludes from its URG revenue requirement the cost of ancillary services. The remaining ISO charges ("other ISO charges" and GMC) are included in SDG&E's URG revenue requirement. In addition, SDG&E excludes the costs for intermediate-term contracts from its proposed URG revenue requirement. SDG&E states it included the costs for intermediate-term contracts in DWR's revenue requirement.

SDG&E states that its proposed revenue requirement for SONGS is based on ICIP and its proposed revenue requirement for purchased power contracts are based on forecasts of deliveries and actual costs.

B. ORA and Intervenors

TURN, Aglet and ORA have all raised generic concerns about accuracy and reliability of concerning utility forecasts.

C. Discussion

SDG&E made a very cursory showing in this proceeding. Its initial testimony consisted of six pages plus three pages of attachments. Similar to PG&E and Edison, we have concerns about the accuracy and reliability of cost forecasts. We will address these concerns by adopting TURN's cost recovery proposal.

As discussed in section VI.C, we reject ICIP pricing for SONGS on the basis that it is not cost-based. However, under the TURN cost recovery proposal, SDG&E will recover all of its actual costs for SONGS. For the purposes of setting an interim URG revenue requirement we will use SDG&E's proposed nuclear generation revenue requirement of $154.132 million.

General agreement exists that purchased power costs should be subject to balancing account treatment. SDG&E provided monthly cost estimates from July 2001 to June 2002 for its bilateral and long term purchased power contracts as well as ISO costs. SDG&E's timeframe of July 2001 through June 2002 is the same time period we used for PG&E and Edison for forecasting purposes. Therefore, we will use SDG&E's proposed revenue requirements of $238.842 for purchased power and $72.886 million for ISO charges for purposes of establishing an interim revenue requirement.

Similar to PG&E and Edison, we exclude recovery of past QF costs in SDG&E's purchased power revenue requirement. To the extent that past QF costs are contained in SDG&E's revenue requirement, SDG&E should not record such amounts in its balancing account.

Although SDG&E has made an effort to exclude costs paid by DWR from its revenue requirement, to the degree that DWR in the future pays for ISO charges or ancillary services, SDG&E should not record such costs in its balancing account for URG costs. Similar to Edison and PG&E, we will revisit SDG&E's URG revenue requirement in its next GRC.

D. Table 3 – Adopted URG Revenue Requirement for SDG&E

San Diego Gas & Electric Company
URG Revenue Requirement

(000's)

	Generation - SONGS	
1	Operating Expenses	
2	Capital Related	
3	Depreciation	
4	Taxes	
5	Return	
6	Gen.Plant	
7	Total	$154,132
	Contracts	
8	QFs	$129,475
9	Interutility	$46,457
10	Bilateral	$62,910
	ISO-Related Charges	
	Other ISO Charges	52,963
	Grid Management Charge	19,923
14	***Total URG Revenue Requirement***	$465,860

VIII. Income Taxes

A. Aglet

Aglet asserts that the current energy situation constitutes an extraordinary circumstance, which warrants examination of existing policy for determining PG&E and Edison's income tax revenue requirement. In D.84-05-036, the Commission stated it would assume a "separate return basis" and solely consider the utilities' operations in calculating the utility's income tax revenue requirements. Aglet asserts that the application of D.84-05-036 would result in extended time differences between receipt of income tax revenue requirements in 2001 and potential later payments of actual income taxes.

To remedy the situation, Aglet recommends that PG&E and Edison submit annual income tax compliance filings after utility recovery of transition cost undercollections is known to determine: (1) the timing of balancing account debits for income tax revenue requirements, (2) the timing of actual income tax expenses, and (3) the time value of funds paid by ratepayers in 2001 and 2002 that offset income taxes paid by the utilities after any recovery of transition cost undercollections. Until the Commission reviews the compliance filings, income tax revenue requirements for PG&E and Edison unpaid taxes should be subject to refund or true-up.

B. Edison

Edison adamantly opposes Aglet's recommendation. Edison complains that Aglet modified its recommendation several times during the proceeding and that it was denied the opportunity to fully respond. Edison also asserts that Aglet's proposal is inconsistent with D.84-05-036, and thus violates Commission policy.

Edison also asserts that the extraordinary exception Aglet relies upon does not apply in the instant case. In addition, Edison contends that Aglet has the burden of showing a variance from D.84-05-036 is warranted, a burden which Edison believes Aglet has not met. Lastly, Edison argues that Aglet's proposal would result in a violation of Internal Revenue (IRS) Code Section 168(I)(9). Edison asserts that the penalties for violating IRS Code are enormous because Edison would be precluded from using accelerated tax depreciation for all of its currently owned rate regulated property.

C. PG&E

PG&E accepts in limited part Aglet's proposal. PG&E states that if it recovers its approximate $10 billion in undercollections, PG&E is willing to ensure that ratepayers are provided with the full time value of money associated with the tax benefit that PG&E is currently receiving because of the undercollection, and the tax liability that PG&E will incur when it receives the revenues to recover the undercollection.

PG&E explains that for expense balancing accounts, revenues are just as likely to exceed expenses, giving rise to a tax liability (as well as an overcollection to be returned to ratepayers later), as they are to under-recover expenses, giving rise to a tax benefit (as well as an undercollection to be recovered from ratepayers later.) Because the tax consequences can go either way, and are expected to even out over time as balancing accounts fluctuate above and below even, the Commission's ratemaking treatment does not track, or adjust for, the periodic tax liabilities and benefits associated with expense balancing accounts.

However, in this instance PG&E states that while Aglet's treatment would be atypical, PG&E agrees that it would be appropriate in this case to hold proceedings to ensure that ratepayers receive the full time value of money associated with timing of the occurrence of the related tax benefit, and the later occurrence of the "offsetting" tax liability. PG&E suggests that the Commission should schedule workshops to address the issue. PG&E's concurrence however, is clearly contingent on the Commission adopting PG&E's proposals to recover its undercollection.

D. Discussion

We agree with Aglet that the potential exists for extended time differences between receipt of income tax revenue requirements in 2001 and later payments of actual income taxes. As a consequence of this timing difference between receipt of revenues and actual payment of taxes, Edison and PG&E benefit from the time value of money. Aglet's proposal to make Edison and PG&E's income tax revenue requirements subject to refund or true-up provides an opportunity to review in more detail the actual tax consequences in the utilities' next GRCs. Specifically, whether the benefits received are an extraordinary situation not contemplated in D.84-05-036.

In addition, although it is not clear what evidence Edison was denied an opportunity to present, deferring resolution of this matter to the utilities' next GRC would provide Edison an opportunity to present further testimony. Thus, we would resolve Edison's first concern about being denied an opportunity to fully respond in its testimony to Aglet's proposal. However, it appears that Edison's primary objections, inconsistencies with D.84-05-036 and IRS Code Section 168(I)(9), are legal rather than factual issues that Edison addressed in its briefs.

A more serious issue raised by Edison is its dire prediction that a violation of IRS Code Section 168(I)(9) would result in enormous negative tax consequences by precluding Edison from using accelerated tax depreciation for all of its currently owned rate regulated property. We have reviewed IRS Code Section 168(I)(9)[37] and fail to see how the submission of annual income tax compliance filings that provide information concerning the timing of balancing account debits and actual income tax expenses, as well as a calculation concerning the time value of funds would violate IRS Code Section 168.

In its comments to the draft decision, Edison should identify the specific wording from the text of IRS Code Section 168(I)(9) which it believes Aglet's proposal violates and explain in more detail the claimed violation. Absent a convincing explanation, we will adopt Aglet's recommendation and set Edison's and PG&E's generation income tax revenue requirement subject to refund.

IX. Balancing Accounts

In this section, we address the balancing account proposals of PG&E and Edison.

A. PG&E

PG&E proposes a continuation of the mechanisms adopted by the Commission in the original Competition Transition Cost Proceedings (D.96-06-060 and D.97-11-074) with some modifications in response to the decision issued in Phase 1 of the RSP (D.01-03-082).[38] Specifically, PG&E

[37] See Appendix C.

[38] PG&E also proposes balancing account treatment in the event the Commission terminates the rate freeze in this phase of the RSP. The issue of whether the rate freeze has ended is outside the scope of this decision, thus we do not address the balancing accounts proposals PG&E makes in the event the rate freeze has ended. This issue is subject to further consideration pursuant to D.02-01-001.

proposes to retain the TRA, TCBA, and Generation Memorandum Account (GMA) and create the Procurement Surcharge Balancing Account (PSBA) as proposed in AL 2096-E.

PG&E proposes to maintain the TRA and to transfer to the TRA any overcollected or undercollected balances contained in the GMA. Further, costs associated with the ISO, bilateral contracts and block forward markets would no longer be recorded in the TRA, but rather would be recorded in the PSBA.

PG&E proposes only minor change to the TCBA. Specifically, PG&E proposes to no longer record the costs associated with QFs, PPAs and irrigation districts in the TCBA. Instead, these costs would be recorded in the PSBA.

PG&E also proposes to continue the GMA, however, transferring GMA balances, both debits and credits, to the TRA on monthly basis, rather than annually to the TCBA.

PG&E proposes to establish the PSBA to record the revenues associated with the three-cents surcharge adopted in D.01-03-082 and revenues associated with the one-cent surcharge adopted in D.01-01-018. The PSBA would record costs related to the ISO, bilateral contracts, block forward market, QFs, PPAs, irrigation districts and DWR. PG&E also requests that the Commission adopt a trigger mechanism to implement any rate increase that may be necessary to pay DWR if the balance exceeds a threshold amount. Absent the implementation of a trigger mechanism, PG&E proposes that any undercollection remain in the PSBA for a true-up through an annual AL filing, or by any other means deemed appropriate by the Commission.

B. Edison

Edison proposes to create five new balancing accounts related to URG. Four of the balancing accounts Edison proposes to establish are (1) the Edison-owned or Native Load Generation Balancing Account (NLBA); (2) the QF Balancing Account (QFBA); (3) the DWR Balancing Account (DWRBA); and (4) the ISOBA.[39]

In the NLBA, Edison proposes to record on a monthly basis the costs associated with its own generation, which will include:

1. Actual on-going operating costs for Palo Verde, Mohave, Four Corners, and Catalina;

2. Authorized on-going operating costs for Hydro;

3. SONGS ICIP revenue requirement; and

4. Actual capital costs, including a full return on Edison's generation rate base.

In the QFBA, Edison proposes to record the monthly costs associated with its purchased power such as QF contract costs, bilateral contract costs and interutility contract costs.

In the ISOBA, Edison proposes to record all payments it makes to the ISO for costs associated with ancillary services and uplift charges. Edison states that it has not made payments to the ISO for costs associated with ancillary services due to its financial situation, but that it continues to pay the ISO for certain incurred uplift charges.

In the DWRBA, Edison proposes to record all payments it makes to DWR for the costs DWR incurs to procure energy on behalf of Edison customers.

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[39] The balancing accounts have been renamed to better identify the costs to be included in the balancing accounts.

Further, when Edison resumes procurement responsibilities, Edison proposes to record in the DWRBA all procurement costs incurred by Edison in order to provide for the net-short needs of Edison's retail customers. Edison describes such costs as including but not limited to credit and collateral costs, brokerage costs, and capacity and energy payments.

Edison believes that the implementation of the above four balancing accounts is reasonable as an interim measure, pending a full cost of service review in Edison's 2003 GRC. Edison states that the four new balancing accounts should be effective on January 1, 2001 for the capital-related costs (depreciation/amortization, return, and taxes) associated with Edison's own generation assets and February 1, 2001 for non-capital-related costs. Once the new ratemaking mechanisms are approved, Edison proposes to transfer applicable past recorded amounts from the TCBA, GMAs, and Energy Procurement Surcharge Balancing Account (EPSBA) to the new balancing accounts.

In addition, Edison proposes to establish a fifth balancing account, the Net Undercollected Amount Account (NUAA), to track past generation-related undercollections as of January 31, 2001. Edison proposes to identify and record all past undercollections in the NUAA until a legislative or regulatory plan is implemented.

On a monthly basis, Edison proposes to record actual costs[40] associated with its own generation, purchased power, DWR, and ISO charges in the

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[40] Edison also proposes to record "authorized revenues" like ICIP which are not necessarily reflective of actual cost incurred.

applicable balancing account. On a monthly basis, Edison also proposes to record generation revenues in each balancing account. Thus, Edison contends that each balancing account will track, on a monthly basis, the recorded costs compared to generation revenues.

Edison proposes to determine, on a monthly basis, the amount of generation revenues to record in each balancing account by using "dedicated rate components." Edison calculated the dedicated rate components (or average rates necessary for it to recover URG costs) based on its estimated 2002 revenue requirement and a calendar year 2002 sales forecast. Although Edison states that a sales forecast is necessary to determine the generation-related dedicated rate components, Edison did not present the sales forecast it used.[41] The table below shows Edison's proposed dedicated rate components.

[41] Edison states it will present the sales forecast to the Commission when it submits its 2003 GRC Notice of Intent. Edison asserts that the sales forecast should not be controversial because Edison will ultimately recover neither more nor less than its recorded costs.

Table ___

Generation-Related Dedicated Rate Components

Line No.	Generation-Related Rate Component	Non "Credit Worthy" Dedicated Rate c/kWh		"Credit Worthy" Dedicated Rate c/kWh		Balancing Account Mechanism
1.	Native Load Generation	1.68		1.68		NLBA
2.	QF contracts	3.35		3.35		QFBA
3.	DWR Payments	3.64	> 4.0 c/kWh	3.64	> 4.0 c/kWh	DWRBA
4.	ISO-Related Charges	0.07		1.03		ISOBA
5.	Total	8.75		9.71		
6.	Bundled Service Sales (GWh)	78,139		78,139		

Edison contends that D.01-03-082 requires Edison to first allocate the approximate 4-cents/kWh surcharge to recover costs recorded in the QFBA, DWRBA, and the ISOBA. Edison proposes different balancing account treatment based on whether the Assembly Bill (AB) 1890 rate freeze is in effect.

Edison also proposes to establish (1) an annual rate true-up mechanism and (2) a trigger mechanism for the purpose of recovering any undercollection or refunding any overcollection. Edison proposes that on November 15th of each year, Edison will file an AL that will set forth dedicated rate components that will provide for recovery of undercollections over the next 12-month period beginning January 1 of the subsequent year. In the event there is an overcollection, the AL will set forth dedicated rate components that would allow for the refund of overcollections over the next 12-month period beginning January 1 of the subsequent year.

Edison proposes a trigger mechanism that takes effect at the end of any month, if the sum of the NLBA, QFBA, DWRBA, and ISOBA balances is equal to or greater than $500 million either over- or undercollected. Under such circumstances, Edison proposes using an AL filing to change rates to recover the undercollection or refund overcollections. Edison proposes that such advice letter become effective 30 days after the filing date. On the effective date, Edison will change rates or surcharges to amortize the over or undercollected balances over the succeeding 12-month period. Further, Edison proposes that after the first time trigger mechanism takes effect, Edison will thereafter review net undercollections or overcollections at the end of each subsequent calendar quarter (instead of monthly) to determine if an additional rate change is needed. Edison states that it needs the ability to raise rates and avoid undercollection of generation-related costs in order to improve its bond rating to investment grade. Edison asserts that Commission approval of Edison's proposals for URG cost recovery and the associated balancing accounts and trigger mechanisms is critical to returning Edison to creditworthy status.[42]

C. TURN

In its testimony, TURN proposes that the Commission set generation revenue requirements by adopting a forecast on an interim basis, but later truing up that forecast against actual recorded costs. TURN asserts that this simplified approach that will develop a revenue requirement without having to decide a number of complex forecasting issues.

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[42] On October 2, 2001, Edison entered into a settlement with the Commission that is designed in part to return Edison to creditworthy status.

In its opening brief, TURN states that the need for new balancing accounts or other cost recovery mechanism depends on whether the rate freeze has ended. TURN believes that any balance recorded prior to when the rate freeze is declared over should not be carried forward, but instead should be written off or transferred to some other account for tracking purposes.

TURN does not oppose the implementation of a trigger mechanism, however, it does oppose the use of an AL to implement a rate change. TURN would support use of an expedited application docket to review requests for rate changes.

D. Aglet

Aglet opposes recording contract costs in any balancing account that would allow post-freeze recovery of costs incurred during the rate freeze. Aglet asserts that such costs should continue to accrue in each utility's TCBA.

Aglet does not object to Edison's proposal to record ISO charges in a separate balancing account, but does not endorse any specific scheme for recovery of the costs in rates. As with contract costs, Aglet contends that the Commission should not allow ISO costs to be recorded in any balancing account that would allow post-rate freeze recovery of costs incurred during the rate freeze.

E. ORA

ORA states that in D.01-03-082, the Commission ordered that the surcharges apply only to purchases of power and that the revenues collected from the surcharges are subject to refund if not used to purchase power. Therefore, ORA contends that the utilities should establish separate balancing accounts to track the different categories of revenue requirements and recovered revenues.

ORA recommends that Edison, PG&E and SDG&E establish a minimum of two separate balancing accounts to record the actual monthly costs associated with purchased power. The first account ORA proposes that the three utilities establish is a Contracts Balancing Account to record the monthly revenue requirement associated with their QF contracts and bilateral contracts, purchase power agreements, irrigation districts, block forward markets, and ancillary service costs and other ISO-related costs. The second balancing account ORA proposes that the three utilities establish is a Procurement Balancing Account to record all payments made to DWR for costs that DWR incurs procuring energy for the utilities' customers.

ORA opposes Edison's proposal to establish a utility-owned generation balancing account. ORA asserts that Edison's approach would provide dollar for dollar recovery for all capital and operating costs related to operating the utilities' own power plants. ORA states that historically, the Commission has not allowed balancing account treatment for generation-related revenue requirements, except for fuel-related costs. ORA contends that historically, the utilities have been held responsible for some business risk associated with providing electric service, and such responsibility provides an incentive for a utility to competently manage its operations and control its costs. ORA argues that establishment of balancing account treatment for utility owned resources would unfairly shift all risk of operating costs to ratepayers with little or no oversight of productivity. ORA proposes that the utilities should record revenues recovered from their fully compensatory UEG rate and operating costs associated with retained generation facilities in the GMA. In their next GRCs, Edison and PG&E can propose disposition of balances in their GMAs.

ORA supports the general concept proposed by Edison to allocate revenues recovered from the generation-related dedicated rate components comprised of the frozen generation-related rate component and from the surcharges. The only difference is that under ORA's proposal, the utilities would not record their rate for utility-owned generation in a balancing account. ORA states that the three utilities should, however, still calculate the fully compensatory rate for ratemaking purposes. If the utilities' frozen or capped generation-related rate exceeds the fully compensatory rate for utility owned generation, ORA advocates allocating the remaining amount among the Contracts Balancing Account, the Procurement Balancing Account and the ISO Balancing Account on the same pro rata basis as the surcharge revenue. ORA also recommends allocating revenues to the balancing account on a pro rata basis as proposed by Edison.

ORA supports the necessity for true-up and trigger mechanisms, but it opposes Edison's proposal to effect these rate changes through the advice letter process. ORA contends that the advice letter process does not provide an adequate forum for the Commission, its staff and interested parties to review and audit the costs and revenues recorded in the balancing account and to properly recommend the disposition of the over- or undercollections. Instead, ORA recommends that the utilities true-up the balancing accounts through annual rate proceedings. ORA also recommends that any significant over- or under-collections which the utilities seek through trigger filings between the annual true-ups should be through a formal rate proceeding. ORA also proposes limiting each utility to one trigger filing per year. ORA supports processing of true-up and trigger filings on an expedited basis.

ORA also opposes Edison's proposal to create NUAA because its establishment is beyond the scope of this proceeding, which is to establish a revenue requirement for URG. ORA also argues that this proceeding does not provide the Commission or interested parties with the time required to appropriately review or audit the balances that Edison proposes to transfer into the NUAA.

F. Discussion

In Section IV, we explained our intent to adopt TURN's proposal for using recorded costs across the board for all URG costs. TURN's cost recovery proposal reflects a straightforward approach that ensures that the utilities recover all actual and reasonably incurred costs and avoids the problems associated with outdated forecasts. In adopting this approach to revenue requirements, we have explicitly determined that we will allow recovery of actual costs rather than taking a forecast approach to setting revenue requirements. We have developed target revenue requirements for purposes of this decision that must be tracked and trued-up when compared with actual, recorded costs. In adopting this cost recovery approach, therefore, we must also allow PG&E, Edison, and SDG&E to establish balancing accounts in order to compare recorded costs with the revenue requirements we adopt here. We do not agree with ORA that the utilities should be precluded from establishing balancing accounts to track costs and revenues associated with utility-owned generation. In fact, we specifically require this balancing account to be established, consistent with adopting TURN's cost recovery approach.

Because we do not address recovery of what were previously determined to be stranded costs in this decision, there is no need to consider Edison's proposal to create the NUAA at this time. In addition, on November 4, 2001, Edison filed Advice Letter 1586-E to establish an account for such costs pursuant to a settlement entered into with the Commission on October 2, 2001 in Case No. 00-12056-RSWL (Mcx). The draft Resolution (Resolution E-3765) regarding this Advice Letter considers the account as well as the disposition of the TCBA, the TRA, and the GABA. The Commission currently plans to consider Resolution E-3765 at the Commission Meeting on January 23, 2002; therefore, we will not address the disposition of these Edison accounts here. Similarly, we will not address Edison's proposal to establish a DWR balancing account in this decision. That issue is being considered in a separate decision in this docket.

We will therefore require PG&E, Edison, and SDG&E to establish the NLBA, the Purchased Power Balancing Account (PPBA), and the ISO Balancing Account (ISOBA). The NLBA will be used to record the actual costs associated with O&M costs for fossil, hydro, and nuclear facilities, as determined in this decision, as well as actual capital costs, including a full return on generation rate base. These costs should be recorded on a monthly basis and compared to the interim revenue requirements adopted herein.

The PPBA will track recorded costs associated with purchased power costs, including QF contract costs, bilateral contract costs, and interutility contract costs. A sub-account within this account should be used to track QF costs. Again, these amounts will be recorded on a monthly basis and compared to the revenue requirements adopted in this decision.

Finally, the ISOBA will be used to record all payments the utilities make to the ISO for costs associated with ancillary services and uplift charges. The utilities will compare these costs, recorded on a monthly basis, to the interim revenue requirements we adopt today. This account will be also be used to record any credits associated with RMR revenues and ancillary services.

Within 15 days from the effective date of this decision, PG&E, Edison, and SDG&E shall file compliance advice letters to establish the NLBA, PPBA, and ISOBA. We recognize that SDG&E currently tracks its URG costs in its Purchased Electric Commodity Account (PECA). SDG&E may modify its PECA to create sub-accounts within the PECA to track recorded costs associated with each cost category identified above, rather than creating entirely new balancing accounts. These ALs will be effective upon review of the Energy Division. We will true these accounts up on a semi-annual basis by AL filing. Each true-up AL shall be filed no later than 30 days after the end of each period. These accounts should remain in place until each utility's respective GRC is completed, at which time any remaining balances should be fully amortized. The utilities should withdraw any advice letters they may have previously submitted that establish balancing accounts or tariffs that are not consistent with this decision.

A general concern we have is about double collection. We are concerned that the utilities may record an actual cost in a balancing account for which DWR is already paying or the utility may already be collecting in another account or seeking in another proceeding.

The utilities are in the best position to determine whether a cost is being paid by DWR or whether the utility is recovering such cost in another account or proceeding. Consequently, we will place the burden on the utilities to ensure that double collection does not occur. Thus, PG&E, Edison and SDG&E should submit AL filings within 30 days of the effective date of decision, stating what, if any, URG costs are reflected in other Commission approved accounts or the utility is seeking in other proceedings, such as PG&E's current attrition request. Such filings should protect against the possibility of PG&E, Edison or SDG&E recovering more than once the same costs.

The purpose of this decision is to establish a revenue requirement for URG. This decision does not set generation rates since the utilities have not provided a definitive sales forecast and we are simultaneously considering the DWR revenue requirement. Both of these pieces of information are critical to determining whether a change in rates is necessary. We must also address the recovery of what were previously determined to be stranded costs and the impact of the accounting changes we adopted in D.01-03-082, including, for example, the reversal of accelerated depreciation. Therefore, the values we adopt here may be modified, as we move forward. Moreover, any rate setting exercise must consider the status of the rate freeze. We do not address Edison's proposal to establish dedicated rate components at this time. We intend to address the above issues very shortly. The assigned Commissioner will issue an ACR to consider the combined impact of this decision and the DWR revenue requirement decision once both decisions are issued.[43] However, we recognize that this approach does not recognize the possibility of a shortfall in revenues for the utilities. Therefore, we direct PG&E, Edison, and SDG&E to establish a balancing account, the Revenue Shortfall Balancing Account (RSBA), to track the billed revenues against authorized revenue requirements. This account will also track any under- or overcollections from the NLBA, PPBA, and the ISOBA. (See Appendix E for an example of how this accounting would work.)

We also defer acting upon the utilities' requests for a trigger mechanism that would allow major rate changes via the advice letter process. We are sympathetic to PG&E's and Edison's circumstances; however, we are concerned that delegating review of requests for rate increases to the advice letter process may conflict with our statutory duty to ensure that rates are just and reasonable. We will address this issue in our decision regarding the need for a rate change.

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[43] Any rate changes for SDG&E shall be addressed in a separate docket, A.00-10-045 et al.

X. Comments on Proposed Decision

The Proposed Decision of ALJ DeUlloa in this matter was mailed to parties on January 18, 2002. Pursuant to Pub. Util. Code § 311(d), the Commission must wait 30 days to take action on this matter, absent an unforeseen emergency or the stipulation of all parties. We must take immediate action in order to facilitate our preparation of a Term Sheet as required by the bankruptcy court in PG&E's bankruptcy proceeding. (Pacific Gas and Electric Company, Case No. 01-30923 DM, United States Bankruptcy Court, Northern District of California, San Francisco Division.) As required by Judge Montali, that Term Sheet must be submitted by February 13, 2002. Therefore, we find that this court-imposed deadline requiring immediate action constitutes an unforeseen emergency (cf. Rule 81(g)) and we reduce the comment and review period. Comments on this proposed decision must be filed and served by February 1, 2002. Comments should also be served electronically on the ALJ at jrd@cpuc.ca.gov and other parties in addition to regular filing and service. No reply comments will be accepted.

Findings of Fact

1. Consistent with D.01-01-061 and D.01-10-067, the scope of this decision is limited to establishing cost-based revenue requirements on a going forward basis.

2. The scope of this phase of the RSP is the determination of URG revenue requirements. Issues concerning stranded cost recovery or ending of the rate freeze are not addressed.

3. Issues concerning DWR's revenue requirement are outside the scope of this phase and are being specifically addressed in a separate phase of this proceeding.

4. Under cost-of-service ratemaking, utilities should recover actual and reasonably incurred costs.

5. The current energy situation has required expeditious preparation of forecasts by the utilities and a similar rapid review by staff, intervenors and the Commission.

6. As a consequence of time constraints, the costs presented at hearing have undergone a less thorough review than is standard in a GRC or similar proceeding.

7. TURN's cost recovery proposal reflects a straightforward approach that ensures the utilities will recover actual and reasonably incurred costs.

8. TURN's cost recovery proposal avoids the problems associated with outdated forecasts.

9. Limiting recovery to actual recorded costs is reasonable in situations where the type of forecast accuracy normally attained in a GRC is not achievable.

10. An interim revenue requirement is appropriate until cost issues can be addressed in upcoming GRCs.

11. Balancing account treatment for all recorded costs captures the differences between the forecasts underlying the revenue requirement and the actual recorded costs.

12. Under the present circumstances, the work associated with reviewing some utility costs, such as O&M costs, for reasonableness outweighs the savings benefits to consumers.

13. PG&E's forecast of operating expenses is overstated due to PG&E's assumption of continually rising fuel prices.

14. Suspension of reasonableness review for PG&E's fossil and hydro generation O&M costs reduces financial risk to PG&E by guaranteeing that it will recover its actual recorded costs without concern for reasonableness review.

15. Reasonableness review plays a critical incentive role in motivating utilities to make sound economic decisions that benefit both shareholders and ratepayers.

16. Reasonableness reviews constitute a minimum concession by utilities in exchange for the benefit of assured recovery of all reasonably incurred expenses and a guaranteed return on equity.

17. Suspension of reasonableness review reflects a response to the strains placed on parties from returning to the practice of establishing a cost-based revenue requirement and not a departure from the practice of using reasonableness reviews in cost-based regulation.

18. Use of net book value for establishing rate base provides PG&E an opportunity to recover its original investment in plant. Net book value should be used to establish rate base for PG&E's non-nuclear generation since net book value reflects original cost less accumulated depreciation.

19. In D.01-10-067, the Commission addressed and rejected PG&E's proposal to use a market value of its hydroelectric assets in determining a URG revenue requirement, and also rejected PG&E's proposal to recover balances in the TCBA in its URG revenue requirement.

20. PG&E's proposed net book values in scenario three for fossil and non-fossil generation is combined with amounts contained in balancing accounts for transition costs. These transition cost amounts cannot be easily delineated.

21. PG&E does not provide sufficient information to determine the net book value of its fossil and hydro generation.

22. PG&E's testimony lacks detailed information and analysis concerning how PG&E determined rate base from its proposed starting point balances. PG&E's testimony lacks detailed information about the amount of deferred taxes and deprecation taken, and the accuracy or reasonableness of such amounts is also unclear.

23. Under PG&E's 50/50 sharing proposal for Diablo Canyon ratepayers would likely pay in excess of the costs to produce power.

24. PG&E's 50/50 sharing proposal for Diablo Canyon is not be cost-based, does not provide any direct cost benefits to ratepayers, and is premised on the assumption that the rate freeze has ended, a finding that the Commission has not yet reached.

25. ICIP does not produce a cost-based URG revenue requirement.

26. The record is insufficient to determine a cost-based revenue requirement for Diablo Canyon.

27. Adoption of the Diablo Canyon revenue requirement contained in PG&E's second scenario and application of TURN's cost recovery proposal ensures that PG&E suffers no economic harm or taking since PG&E will recover all of its actual and reasonable costs incurred for nuclear generation.

28. Insufficient analysis exists to make a determination as to the reasonableness of PG&E proposed capital additions.

29. No party made a comprehensive cost of capital showing.

30. Gas prices in early 2001 were abnormally high and since then have been declining, therefore, a July 2001 to June 2002 forecast period is preferable to using projected prices for all of 2002. A July 2001 to June 2002 forecast period for gas costs yields the most accurate 2002 revenue requirement for purchased power.

31. ORA's net book value of $985 million as of December 31, 2000, is reasonable for purposes of establishing an interim rate base for PG&E's fossil and hydro generation.

32. PG&E's net book value of $53 million is reasonable for purposes of establishing and interim rate base for EETA.

33. Subject to true-up against actual recorded costs, the Diablo Canyon revenue requirement contained in PG&E's second scenario should be used as an interim revenue requirement since it purportedly relies on cost-based calculations. A Diablo Canyon revenue requirement of $393 million and a rate base of $408 million is reasonable for purposes of establishing an interim URG revenue requirement for PG&E.

34. Depreciation of $56 million, based on a 10-year depreciation life, should be included on an interim basis in PG&E's Diablo Canyon's revenue requirement.

35. PG&E's purchased power costs should be subject to balancing account treatment.

36. PG&E's gas prices for the time period July 2001 to June 2002 should be used to calculate a QF revenue requirement.

37. Past QF costs should be excluded from PG&E's URG revenue requirement.

38. PG&E's estimated costs for bilateral and long-term purchased power contracts during the time period July 2001 to June 2002 should be used to forecast an interim revenue requirement for the year 2002.

39. PG&E's estimated ISO charges and ancillary services costs for the time period July 2001 to June 2002 should be used to forecast an interim revenue requirement for the year 2002.

40. PG&E's URG revenue requirement should reflect costs paid for by PG&E. Costs and charges paid for by DWR should not be included in PG&E's URG revenue requirement or recorded in a balancing account for URG costs.

41. Revenues that PG&E receives for RMR or ancillary services it provides should be used to offset PG&E's URG revenue requirement and such revenues should be recorded as a credit in the appropriate balancing account.

42. A purchased power revenue requirement of $1.830 billion ($1.810 billion plus $20 million for FF&U) is reasonable for purposes of establishing PG&E's interim URG revenue requirement.

43. For purposes of establishing an interim URG revenue requirement, PG&E's forecast of $25 million for total operating expenses for EETA should be used.

44. An EETA revenue requirement of $30 million is reasonable for purposes of establishing PG&E's interim URG revenue requirement.

45. The work necessary to review the reasonableness of Edison's non-nuclear generation O&M costs may outweigh the savings benefits to consumers.

46. Suspension of reasonableness reviews for Edison's O&M costs for fossil and hydro generation reduces Edison's financial risk by guaranteeing the recovery of recorded costs.

47. It is reasonable to reduce by $2 million Edison's fossil and hydro generation revenue requirement to account for suspension of reasonableness review of fossil and hydro O&M costs.

48. A revenue requirement for Edison of $464 million for fossil and hydro generation subject to balancing account treatment is reasonable for purposes of establishing Edison's interim URG revenue requirement.

49. Edison did not provide sufficient information to verify its rate base amount.

50. Edison offered very little specific analysis in its testimony on capital additions.

51. It is reasonable to determine rate base using recorded net book value of plant-in-service as of December 31, 2000.

52. It is reasonable to use Edison's projected capital addition costs for establishing an interim URG revenue requirement.

53. It is reasonable to require Edison to record projected capital addition costs for reasonableness review in its next GRC or similar proceeding.

54. Edison's use of depreciation and amortization schedules based on the expected remaining life of its non-nuclear generation plant is reasonable.

55. It is reasonable to set rate base for SONGS equal to end-of-year 2000 book value (exclusive of capital additions incurred since establishment of ICIP, and subtracting decommissioning costs previously recovered).

56. TURN's cost recovery proposal allows Edison to recover all of its actual and reasonable costs incurred for its nuclear generation on a going forward basis.

57. A revenue requirement of $842 million for nuclear generation subject to balancing account treatment is reasonable for purposes of establishing Edison's interim URG revenue requirement.

58. The timeframe of July 2001 through June 2002 should be used to forecast Edison's 2002 revenue requirement for purchased power.

59. A revenue requirement of $2.425 million for purchased power subject to balancing account treatment is reasonable for purposes of establishing Edison's interim URG revenue requirement.

60. Past QF costs should not be included in Edison's purchased power revenue requirement.

61. To the extent that past QF costs are contained in Edison's revenue requirement, Edison should not record such amounts in its balancing account.

62. A revenue requirement of $68 million for ISO-related charges subject to balancing account treatment is reasonable for purposes of establishing Edison's interim URG revenue requirement.

63. Edison's URG revenue requirement should reflect costs paid for by Edison.

64. To the extent DWR pays for ISO charges or ancillary services, Edison should not record such costs in its balancing account for URG costs.

65. To the extent Edison receives revenues for Reliability Must Run (RMR) or ancillary services it provides, such revenues should be credited to the appropriate balancing account.

66. Edison's last authorized ROE was set based on assumptions that no longer exist.

67. Use of recorded costs to establish a revenue requirement means that Edison's investors face little to no risk of incurring large undercollections and not recovering actual costs.

68. DWR has assumed most of the procurement risks that led to Edison's financial problems.

69. Substantial changes in circumstances warrant a reassessment of Edison's ROE going forward.

70. The reduced ROE balances both ratepayer and shareholder interests.

71. The cost-of-service ratemaking approach we adopt today reduces the risks to investors but should still allow Edison to maintain its financial integrity, attract necessary capital, and compensate investors for the risks assumed.

72. Under the TURN cost recovery proposal, SDG&E will recover all of its actual costs for SONGS.

73. A revenue requirement of $154.132 million for nuclear generation subject to balancing account treatment is reasonable for purposes of establishing SDG&E's interim URG revenue requirement.

74. A revenue requirement of $238.842 for purchased power subject to balancing account treatment is reasonable for purposes of establishing SDG&E's interim URG revenue requirement.

75. A revenue requirement of $72.886 million for ISO charges subject to balancing account treatment is reasonable for purposes of establishing SDG&E's interim URG revenue requirement.

76. Past QF costs should not be included in SDG&E's purchased power revenue requirement.

77. To the extent that past QF costs are contained in SDG&E's revenue requirement, SDG&E should not record such amounts in its balancing account.

78. The potential exists for extended time differences between PG&E and Edison receiving income tax revenue requirements in 2002 and later payments of actual income taxes.

79. Edison and PG&E may benefit from the time value of money due to timing difference between receipt of revenues and actual payment of taxes.

80. We have developed target revenue requirements for purposes of this decision that must be tracked and trued-up when compared with actual, recorded costs. In adopting this cost recovery approach, therefore, we must also

allow PG&E, Edison, and SDG&E to establish balancing accounts in order to compare recorded costs with the revenue requirements we adopt here.

81. The purpose of this decision is to establish a revenue requirement for URG. This decision does not set generation rates since the utilities have not provided a definitive sales forecast and we are simultaneously considering the DWR revenue requirement. We cannot set rates until we have this information, which is critical to determining whether a change in rates is necessary. The rate setting exercise must also consider the status of the rate freeze.

82. The possibility exists that the utilities may recover more than once the same costs.

Conclusions of Law

1. The recovery of "past expenses" is a distinct issue from establishing a URG revenue requirement based on prospective costs.

2. ALJ DeUlloa's July 18, 2001 ruling that (1) the scope of the evidentiary hearing is the determination of URG revenue requirements; and that (2) issues concerning stranded cost recovery or the end of the rate freeze are outside the scope of this phase should be affirmed.

3. The possibility of later modifications to the utilities' URG revenue requirements to account for past stranded or uneconomic costs should not be precluded.

4. A forecast should not serve as a basis for establishing a revenue requirement for later use in setting rates in the absence of the type of evaluation that typically occurs in a GRC or similar proceeding.

5. The utilities' URG revenue requirements should provide for recovery of actual recorded costs.

6. TURN's cost recovery approach should be adopted.

7. Only interim URG revenue requirements should be adopted in this phase of the RSP

8. The revenue requirements of Edison and PG&E should be adjusted to reflect a partial suspension of reasonableness review.

9. URG revenue requirements based on more detailed showings and review should be adopted in the utilities' respective GRC proceedings.

10. The URG revenue requirements adopted should cover the time period January 2002 to December 2002.

11. TURN's proposal to use recorded costs for generation operating expenses, subject to existing Commission ratemaking policies, should be adopted.

12. For purposes of establishing an interim URG revenue requirement for PG&E, ORA's forecast of $549 million for total operating expenses for fossil and hydro generation should be adopted with small modification to reflect the suspension of reasonableness review for O&M costs for hydro and fossil generation.

13. As an interim measure, PG&E's fossil and hydro generation O&M costs should not be subject to reasonableness review.

14. Suspension of reasonableness review for PG&E's fossil and hydro generation O&M costs should be accompanied by an equivalent reduction on ROE. The O&M revenue requirement adopted for PG&E's fossil and hydro generation should be reduced by 2.12% to adjust for suspension of reasonableness review.

15. PG&E should be made whole for its actual and reasonably incurred operating expenses.

16. ORA's recommendation to use the lessor of recorded costs versus PG&E's forecast should be rejected since the approach is biased against PG&E.

17. PG&E's next GRC should determine depreciation life for Diablo Canyon based on the useful life of the plant.

18. PG&E's nuclear generation costs should be subject to reasonableness review since we have modified PG&E's method of recovering such costs.

19. PG&E should seek review of any capital additions in its next GRC. Any plant previously excluded from rate base should continue to be excluded.

20. The ROE authorized in D.00-06-040 should be used until PG&E's next cost of capital proceeding or GRC.

21. As an interim measure, reasonableness review for Edison's O&M costs for fossil and hydro generation should be suspended.

22. Reduction of risk of reasonableness review should be accompanied by an equivalent reduction of Edison's URG revenue requirement.

23. In its next GRC, Edison should present detailed testimony to support its rate base, capital additions and requested return on rate base.

24. ICIP pricing is inconsistent with Pub. Util. Code § 360.5 and D.01-06-041.

25. Pub. Util. Code § 360.5 requires the Commission to determine retail rates based on the costs of the utility's own generation.

26. Modification of ICIP pricing does not violate Pub. Util. Code § 367(a)(4).

27. The profit sharing element of ICIP is not a utility cost.

28. ICIP should be modified.

29. Changes in law, market and regulatory environment have occurred that warrant eliminating or modifying ICIP to produce a cost-based rate.

30. Pursuant to Pub. Util. Code § 360.5, the Commission may pursue cost-based pricing for nuclear generation.

31. TURN's request to modify the initial starting point revenue requirement by reducing the SONGS ICIP by 20% should be denied.

32. Edison's nuclear generation costs, including O&M, should be subject to reasonableness review and balancing account treatment.

33. Edison's purchased power costs should be subject to reasonableness review.

34. Edison's ROE should be set at a level sufficient to attract capital investment and accelerate the improvement of Edison's standing in the credit markets.

35. Edison's last authorized ROE was set in contemplation of potential risks related to competition and restructuring.

36. The law and policies concerning divestiture and accelerated depreciation have changed since Edison last authorized ROE.

37. Edison investors are entitled to a lower ROE than 11.6%.

38. Edison's authorized ROE should be reduced to 10% as an interim measure, until Edison's next cost-of-capital or similar proceeding.

39. Ratepayers should not have to pay for a return that is based on an ROE set when Edison faced competition. AB 6X requires that the utilities retain generating-related assets until at least 2006 and we are now allowing cost recovery of these assets under cost-of-service regulation. By allowing balancing account treatment and ensuring recovery of recorded costs, Edison faces little risk of recovery.

40. SDG&E's nuclear generation costs, including O&M, should be subject to reasonableness review and balancing account treatment.

41. SDG&E's purchased power costs should be subject to reasonableness review.

42. In its next GRC, SDG&E should present detailed testimony to support its URG revenue requirement.

43. Edison and PG&E's income tax revenue requirements should be subject to refund or true-up in the utilities' next GRC to provides an opportunity to examine in more detail the actual tax consequences from differences in receipt of payment and actual tax payments and also whether the benefits received are an extraordinary situation not contemplated in D.84-05-036.

44. It is reasonable to establish balancing accounts to record the incurred costs related to PG&E, Edison, and SDG&E's native load, purchased power, and ancillary services.

45. It is reasonable to credit revenues related to RMR units and ancillary services to the ISOBA.

46. Because we are not setting rates in this decision, we recognize that this approach does not recognize the possibility of a shortfall in revenues for the utilities. It is reasonable that PG&E, Edison, and SDG&E should establish a balancing account to track their respective billed revenues against the revenue requirements authorized in today's decision.

47. PG&E, Edison and SDG&E should bear the burden of ensuring that URG costs are not collected more than once.

48. This decision should be effective today so that the utilities may expeditiously implement the revenue requirements set forth in this decision.

49. It is reasonable to determine that the bankruptcy court's deadline constitutes an unforeseen emergency (Cf. Rule 81(g)) and it is reasonable to reduce the comment and review period.

ORDER

IT IS ORDERED that:

1. The cost recovery approach of The Utility Reform Network (TURN) is adopted.

2. Consistent with the direction of this decision, the utility retained generation (URG) revenue requirement of Pacific Gas and Electric Company (PG&E) for January 2002 to December 2002 is $2.875 billion subject to balancing account treatment. (See Table 1, page 33.)

3. Consistent with the direction of this decision, the URG revenue requirement of Southern California Edison Company (Edison) for January 2002 to December 2002 is $3.794 billion subject to balancing account treatment. (See Table 2, page 59.)

4. Consistent with the direction of this decision, the URG revenue requirement of San Diego Gas & Electric Company (SDG&E) for January 2002 to December 2002 is $465.860 million subject to balancing account treatment. (See Table 3, p. 63.)

5. PG&E, Edison and SDG&E are authorized to record actual and reasonably incurred generation costs in their respective balancing accounts.

6. Incremental Cost Incentive Pricing (ICIP) is terminated to provide PG&E, Edison and SDG&E cost-based revenues for nuclear generation.

7. Edison and PG&E shall establish memorandum accounts to track the actual tax consequences from differences in receipt of payment and actual tax payments. Unpaid taxes shall be subject to refund or true-up in the utilities' next GRC.

8. PG&E may seek to modify, through an advice letter (AL) filing, the interim revenue requirement to recover, consistent with cost-based principles, capital

additions not reflected in the Office of Ratepayer Advocates' proposed rate base. Any such adjustment shall exclude capital additions previously excluded. Further, such capital additions shall be subject to reasonableness review in PG&E's next utility retained generation.

9. Within 15 days from the effective date of this decision, PG&E, Edison, and SDG&E shall file compliance ALs to establish the Native Load Balancing Account (NLBA), Purchased Power Balancing Account (PPBA), and the Independent System Operator Balancing Account (ISOBA), consistent with the direction provided in this decision. The PPBA shall also include a sub-account to track QF purchases. SDG&E may modify its Purchased Electric Commodity Account (PECA) to create sub-accounts within the PECA to track the recorded costs discussed herein. These ALs are effective as of January 1, 2002 subject to review of the Energy Division to determine that the ALs are in compliance with this decision. PG&E, Edison, and SDG&E shall true these accounts up on a semi-annual basis by AL filing. Each true-up AL shall be filed no later than 30 days after the end of the period. These accounts shall remain in place until each utility's respective General Rate Case is completed, at which time any remaining balances shall be fully amortized. The utilities shall withdraw any ALs they may have previously submitted that establish balancing accounts or tariffs that conflict with this decision. (See Appendix E for an example of how these balancing accounts will work.)

10. Consistent with the provisions of Ordering Paragraph 9, PG&E, Edison, and SDG&E shall establish a balancing account (Revenue Shortfall Balancing Account) to track their respective billed revenues against the revenue requirements authorized in today's decision. This account shall also track any

under- or overcollections from the NLBA, the PPBA, and the ISOBA. (See Appendix E for an example of how these balancing accounts will work.)

11. PG&E, Edison and SDG&E shall file advice letters within 30 days of the effective date of decision, stating what, if any, URG costs are reflected in other Commission-approved accounts or the utility is seeking in other proceedings. These advice letters shall become effective 40 days after filing, unless suspended by the Energy Division.

This order is effective today.

Dated ____________________________, at San Francisco, California.

APPENDIX A
Page 1

PACIFIC GAS AND ELECTRIC COMPANY
2001 REVENUE REQUIREMENT
SCENARIO 1
(Millions of 2001 Dollars Unless Otherwise Indicated)

Line No.	Description	Fossil and Hydro	Diablo Canyon	Purchased Power Costs[1]	Energy Transaction Administration[2]	Total Generation	Line No.
		(a)	(b)	(d)	(e)	(f)	
1	**REVENUE REQUIREMENT:**	919	1,275	4,195	30	6,418	1
	OPERATING EXPENSES:						
2	O&M Expenses	280	N/A	4,149	13		2
3	Administrative and General	79	N/A	-	4		3
4	Uncollectibles	2	N/A	11	0		4
5	Franchise Requirements	8	N/A	35	0		5
6	Subtotal Expenses:	369	N/A	4,195	17		6
	TAXES:						
7	Property	46	N/A	-	1		7
8	Payroll	4	N/A	-	1		8
9	Business and Other	0	N/A	-	0		9
10	State Corporation Franchise	23	N/A	-	0		10
11	Federal Income	81	N/A	-	2		11
12	Total Taxes	155	N/A	-	4		12
13	Depreciation	156	N/A	-	4		13
14	**Total Operating Expenses**	680	N/A	4,195	25		14
15	Net for Return	239	N/A	-	5		15
16	Rate Base	2,624	N/A	-	53		16

[1] PG&E states that Purchased Power costs include payments made under QF contracts, Bilateral contracts, and Ancillary Services agreements.

[2] PG&E states that Electric Energy Transaction Administration costs include the costs of activities associated with purchasing electricity from the market, purchasing electricity under contracts with QFs and under other power purchase agreements, and managing PG&E's retained generation portfolio. They do not include commodity costs.

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Page 2

PACIFIC GAS AND ELECTRIC COMPANY
2001 REVENUE REQUIREMENT
SCENARIO 2
(Millions of 2001 Dollars Unless Otherwise Indicated)

Line No.	Description	Fossil and Hydro	Diablo Canyon	Purchased Power Costs[1]	Energy Transaction Administration[2]	Total Generation	Line No.
		(a)	(b)	(d)	(e)	(f)	
1	**REVENUE REQUIREMENT:**	2,039	393	1,321	30	3,783	1
	OPERATING EXPENSES:						
2	O&M Expenses	221	273	1,306	13		2
3	Administrative and General	79	32	-	4		3
4	Uncollectibles	5	1	3	0		4
5	Franchise Requirements	17	3	11	0		5
6	Subtotal Expenses:	322	309	1,321	17		6
	TAXES:						
7	Property	106	3	-	1		7
8	Payroll	4	11	-	1		8
9	Business and Other	0	0	-	0		9
10	State Corporation Franchise	78	(4)	-	0		10
11	Federal Income	281	(19)	-	2		11
12	Total Taxes	469	(10)	-	4		12
13	Depreciation	421	56	-	4		13
14	**Total Operating Expenses**	1,213	356	1,321	25		14
15	Net for Return	826	37	-	5		15
16	Rate Base	9,056	408	-	53		16

[1] PG&E state that Purchased Power costs include payments made under QF contracts, Bilateral contracts, and Ancillary Services agreements.
[2] PG&E states that Electric Energy Transaction Administration costs include the costs of activities associated with purchasing electricity from the market, purchasing electricity under contracts with QFs and under other power purchase agreements, and managing PG&E's retained generation portfolio. They do not include commodity costs.
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Page 3

PACIFIC GAS AND ELECTRIC COMPANY
2001 REVENUE REQUIREMENT
SCENARIO 3
(Millions of 2001 Dollars Unless Otherwise Indicated)

Line No.	Description	Fossil and Hydro	Diablo Canyon	Purchased Power Costs[1]	Energy Transaction Administration[2]	Total Generation	Line No.
		(a)	(b)	(d)	(e)	(f)	
1	**REVENUE REQUIREMENT:**	3,388	2,173	4,195	31	9,787	1
	OPERATING EXPENSES:						
2	O&M Expenses	280	601	4,149	13		2
3	Administrative and General	79	-	-	4		3
4	Uncollectibles	9	5	11	0		4
5	Franchise Requirements	28	18	35	0		5
6	Subtotal Expenses:	396	625	4,195	17		6
	TAXES:						
7	Property	13	-	-	1		7
8	Payroll	4	-	-	1		8
9	Business and Other	0	-	-	0		9
10	State Corporation Franchise	14	122	-	0		10
11	Federal Income	49	278	-	2		11
12	Total Taxes	79	400	-	4		12
13	Depreciation	2,770	1,101	-	5		13
14	**Total Operating Expenses**	3,245	2,125	4,195	26		14
15	Net for Return	143	48	-	5		15
16	Rate Base	1,569	525	-	53		16

[1] PG&E state that Purchased Power costs include payments made under QF contracts, Bilateral contracts, and Ancillary Services agreements.
[2] PG&E state that Electric Energy Transaction Administration costs include the costs of activities associated with purchasing electricity from the market, purchasing electricity under contracts with QFs and under other power purchase agreements, and managing PG&E's retained generation portfolio. They do not include commodity costs.

(END OF APPENDIX A)

APPENDIX B
Page 1

IRS Code Section 168(I)(9) states:

i) Definitions and special rules
For purposes of this section -

…

(9) Normalization rules

(A) In general

In order to use a normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2) -

(i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and

(ii) if the amount allowable as a deduction under this section with respect to such property differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

(B) Use of inconsistent estimates and projections, etc.

(i) In general
One way in which the requirements of subparagraph (A) are not met is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with the requirements of subparagraph (A).

(ii) Use of inconsistent estimates and projections
The procedures and adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (A)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other 2 such items and with respect to the rate base.

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Page 2

(iii) regulatory authority
The Secretary may by regulations prescribe procedures and adjustments (in addition to those specified in clause (ii)) which are to be treated as inconsistent for purposes of clause (i).

(C) Public utility property which does not meet normalization rules
In the case of any public utility property to which this section does not apply by reason of subsection (f)(2), the allowance for depreciation under section 167(a) shall be an amount computed using the method and period referred to in subparagraph (A)(i).

(END OF APPENDIX B)

APPENDIX C
Page 1
LIST OF ACRONYMS

A. - Application
A&G – Administrative and General
AB – Assembly Bill
ACR – Assigned Commissioner's Ruling
AFUDC – Allowance for Funds Using During Construction
Aglet – Aglet Consumer Alliance
AL – Advice Letter
ALJ – Administrative Law Judge
APS – Arizona Public Service
CAC – Cogeneration Association of California
D. – Decision
Diablo Canyon – Diablo Canyon Power Plant
DWR – Department of Water Resources
DWRBA – DWR Balancing Account
Edison – Southern California Edison Company
EETA – Electric Energy Transaction Administration
EPSBA – Energy Procurement Surcharge Balancing Account
FERC – Federal Energy Regulatory Commission
FF&U – Franchise Fees and Uncollectibles
GABA – Generation Asset Balancing Asset
GMA – Generation Memorandum Account
GMC – Grid Management Charge
GRC – General Rate Case
GWh – gigawatt hours
ICIP – Incremental Cost Incentive Pricing
IER – Incremental Energy Rate
IRS – Internal Revenue Code Section
ISO – Independent System Operator
ISOBA – Independent System Operator Balancing Account
Kwh – kilowatt-hour
MOU - Memorandum of Understanding
MW – megawatts
NLBA – Native Load Generation Balancing Account
NRC – Nuclear Regulatory Commission

APPENDIX C
Page 2

NUAA – Net Undercollected Amount Account
NUIP – Nuclear Incentive Program
O&M – Operating and Maintenance
ORA – Office of Ratepayer Advocates
PBR – Performance-Based Ratemaking
PECA – Purchased Electric Commodity Account
PG&E – Pacific Gas and Electric Company
PGE – Portland General Electric
PPA – Power Purchase Agreements
PPBA – Purchase Power Balancing Account
PSBA – Procurement Surcharge Balancing Account
QF – Qualifying Facility
QFBA – Qualifying Facility Balancing Account
RMR – Reliability Must Run
ROE – Return on Equity
ROR – Rate of Return
RSBA – Revenue Shortfall Balancing Account
RSP – Rate Stabilization Proceeding
SDG&E – San Diego Gas & Electric Company
SONGS – San Onofre Nuclear Generating Station
SRAC – Short Run Avoided Cost
TCBA – Transition Asset Balancing Asset
TRA – Transition Revenue Account
TURN – The Utility Reform Network
UFE – Unaccounted for Energy
URG – Utility Retained Generation

(END OF APPENDIX C)

APPENDIX D

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(END OF APPENDIX D)

APPENDIX E

Sample Balancing Account Procedures

1. Assume that recorded costs for native load are $1,500.
2. Assume that the interim revenue requirement for native load is $2,000.
3. Assume that recorded costs for purchased power are $1,800.
4. Assume that the interim revenue requirement for purchased power is $1,000.
5. Assume that recorded costs for ISO charges and ancillary services are $800.
6. Assume that the revenue requirement for ISO charges and ancillary services is $500.
7. Assume that total interim revenue requirements are $3,500 (per previous examples).
8. Assume that billed revenues total $3,700.
9. The net effects of Steps 1-6 equal an undercollection of $600.

Then: NLBA

1. Recorded costs = $1,500	2. Interim revenue requirement = $2,000
Undercollection = $500	

PPBA

3. Recorded costs = $1,800	4. Interim revenue requirement = $1,000
	Overcollection = $ 200

ISOBA

5 Recorded costs = $800	6. Interim revenue requirement = $500
Undercollection = $300	

RSBA

7. Interim revenue requirements = $3,500	8. Billed revenues = $3,700
9. Net of Steps 1-6 = 600	
Undercollection = $ 400	

(END OF APPENDIX E)